Proceeding 911586

ERCB

Call for Information

Altamont Gas Transmission Company and Pacific Gas Transmission Company Proposals for Pipelines to California

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ENERGY RESOURCES CONSERVATION BOARD

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Altamont Gas Transmission Company and
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Proposals for Pipelines to California

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1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

The Lieutenant Governor in Council, by Order in Council, requested the Energy Resources Conservation Board (ERCB or the Board) to conduct a Call for Information on two proposals to construct and operate separate pipeline facilities for the removal of Alberta gas to markets in the United States, particularly California. Both proposals would receive gas from the Alberta NOVA system, with one proposal starting at Wildhorse, at the Alberta-Montana border (**Altamont/Kern River Project**) and the other proposal starting near Coleman, at the Alberta-British Columbia border (**PGT Expansion Project**). Both projects are scheduled to be in service by 1 November 1993.

The request from the Government of Alberta for the Board to gather information asked that the Board not attempt to reach a conclusion as to whether either of the pipelines should be built. Rather, the objective was to provide information enabling the private sector to make decisions of support or otherwise. Underlying the request was a concern that information available at the time might be insufficient to allow rational decision making and that the gathering, consolidation, and consistent presentation of relevant information would both serve the industry and work to the best interest of the Province by enabling the private sector to make better decisions.

This report, therefore, attempts to meet the challenge entailed in providing information in a way that is objective and helpful, without drawing conclusions regarding the relative merits of the projects. The Board did not attempt to assess each argument put forward by the proponents, as that could have crossed what might be described as a fine line implicit in the mandate as expressed by the Government of Alberta. In several areas, the Board provides some interpretive or admonitory comment on specific matters. Such comments appear in italics in this Executive Summary and throughout the report.

Interested parties are encouraged to peruse the information provided in response to the Call for Information and might find it useful to review the final statements submitted by each of the parties with a direct interest in this proceeding. These final statements crystallize the essential arguments supporting each proposal, and should provide other interested parties an overview of the various points of view.

The report follows the general outline of information as requested in the initial Call for Information (see Appendix A). Its major categories are set out below:

- Market information is discussed in Chapter 3, including the views of each proponent on future demand for natural gas, existing pipeline capacity and requirements, and contractual commitments to markets.

- Ex-Alberta facilities are discussed in Chapter 4, including views on construction schedules, costs, rate design, netbacks, and contractual transportation commitments.

- Intra-Alberta Pipeline facilities, including NOVA Corporation of Alberta (NOVA) costs, the impact on the cost of service, and environmental considerations, are discussed in Chapter 5.

- The availability of supplies of natural gas from Alberta is discussed in Chapter 6.

- Regulatory issues, including the question of the influence of the CPUC, are set out in Chapter 7.

- The concluding Chapter 8 provides commentary on significant differences in views of the proponents on selected issues, including the need for additional capacity, markets, netbacks, projects' costs efficiency and the interests of producers.

The volume of information submitted and the complexity of issues call for a comprehensive Executive Summary. Divided into two parts, the first summarizes the basic information filed and discussed at the oral session. The second lays out selected issues facing the producing industry.

1.2 SUMMARY OF INFORMATION FILED

Description of The Projects

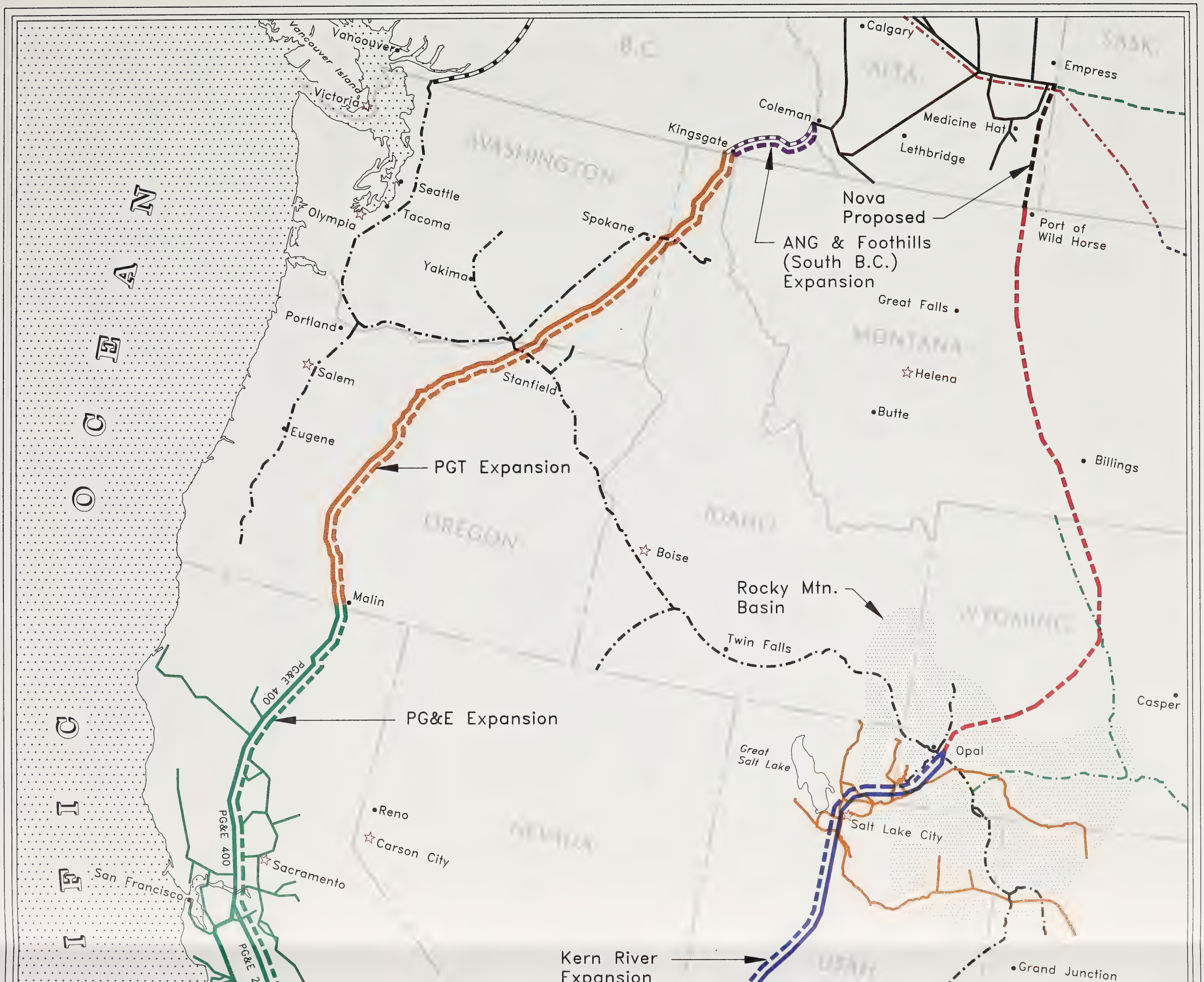
Altamont/Kern River Project

Altamont Gas Transmission Company (Altamont) proposes to construct a pipeline from the Alberta-Montana border near the Port of Wild Horse, Montana, to transport 719 MMcf/d to a connection with the Kern River Gas Transmission Company (Kern River) near Opal, Wyoming. Construction is expected to be complete in 6 months to satisfy an in-service date of 1 November 1993. The Kern River base system originates at points of interconnection with the pipelines of Northwest Pipeline Corporation (Northwest), Colorado Interstate Gas Company (CIG), and Questar Pipeline Company (Questar) near Opal in Wyoming and extends generally in a southwesterly direction through Utah and Nevada into southern California. The base system then converges with the Mojave Pipeline Company (Mojave). This segment is referred to as the Common Facilities, and terminates in Kern County near Bakersfield, California (see Map 1). The Common Facilities will be expanded by either 642 MMcf/d to accommodate both Kern River and Mojave or by at least 452 MMcf/d to accommodate just Kern River. Construction is expected to be completed in 10 months for an in-service date matching that of Altamont.

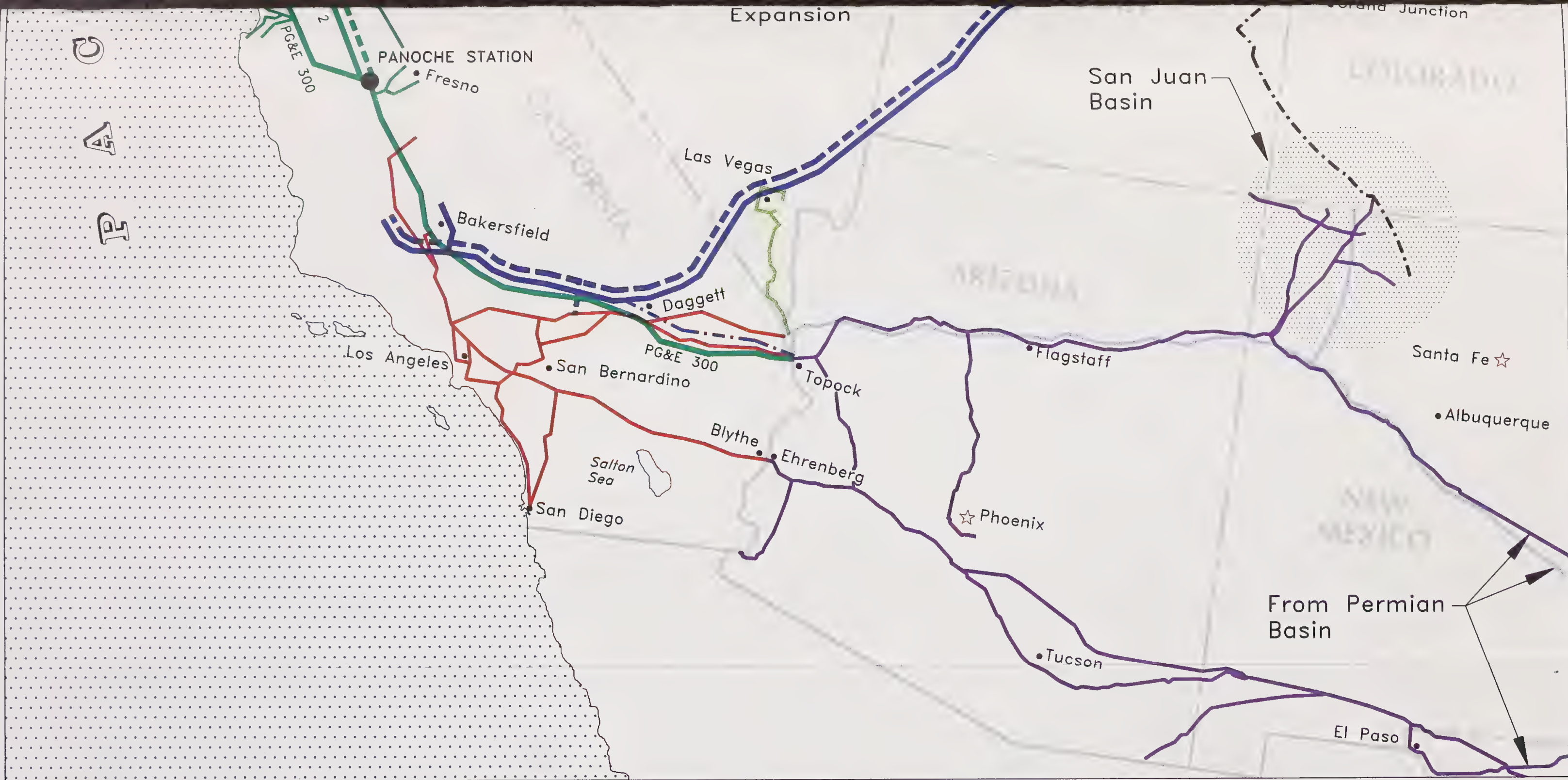
PGT Expansion Project

The PGT Expansion Project involves simultaneous expansions on Alberta Natural Gas Company Ltd. (ANG), Foothills Pipeline Company (Foothills), Pacific Gas Transmission Company (PGT) and Pacific Gas & Electric Company (PG&E). The proposed facilities are designed to deliver 148 MMcf/d to customers in the Pacific Northwest and 755 MMcf/d to California. Construction on PGT commenced in December 1991 at the Sacramento River Delta. Expected in-service date is 1 November 1993.

A summary of the proposed facilities is provided in the following table. For a more detailed description of the facilities and construction schedule, the reader is referred to Sections 4.1 and 4.2 of this report.



Calgary
Empress
Coleman
Kingsgate
Medicine Hat
Lethbridge
Nova Proposed
Port of Wild Horse
ANG & Foothills (South B.C.) Expansion
Great Falls
Helena
Butte
Billings
Vancouver
Vancouver Island
Victoria
Seattle
Tacoma
Olympia
Spokane
Yakima
Portland
Salem
Stanfield
Eugene
PGT Expansion
Boise
Malin
Rocky Mtn. Basin
Twin Falls
Casper
PG&E 400
PG&E Expansion
Great Salt Lake
Opal
Salt Lake City
Reno
Carson City
Sacramento
San Francisco
Kern River Expansion
Grand Junction
OCEAN



LEGEND

Colorado Interstate Gas Co.	Southern California Gas Co.
El Paso Natural Gas Co.	Transwestern Pipeline Co.
Mojave Pipeline	Foothills Pipe Lines Ltd.
Northern Border Pipeline Co.	TransCanada PipeLines Ltd.
Northwest Pipeline Corp.	Westcoast Energy Inc.
Southwest Gas Corp.	Questar Pipeline Co.
ANG & Foothills (South B.C.)	
Pacific Gas Transmission Co.	
Pacific Gas & Electric Co.	
Altamont Gas Transmission Co.	
Kern River Gas Transmission Co.	
Nova Corporation of Alberta.	

MAP 1
ERCB PROCEEDING 911586
CALL FOR INFORMATION
ALTAMONT & PGT PIPELINE PROJECTS

(NTS)

ERCB

Summary of Proposed Facilities

Project	Existing	Expansion
Altamont	-	719 MMcf/d 620 miles of 36-inch
Kern River	700 MMcf/d 683 miles of 36-inch	452 MMcf/d 118.5 MW compression
Common Facilities	Not relevant	452 or 652 MMcf/d
ANG-Foothills	1616 MMcf/d 160 miles of 36-inch 3 compressors-7.5 to 10 MW	877 MMcf/d 48.2 miles of 42-inch 42 MW compression
PGT	1020 MMcf/d 612.5 miles of 42-inch 201.5 MW compression	148 MMcf/d to Pacific Northwest 755 MMcf/d to California 430 miles of 42-inch 22 MW new compression 22 replacement of 7.5 MW
PG&E	Not relevant	755 MMcf/d split between northern and southern California 300 miles of 42-inch and 10 MW compression 115 miles of 36-inch plus 5 existing stations will be modified with another 10.5 MW compression

Market Information

Altamont and PGT submitted their views on the size of the markets proposed to be served, the need for additional pipeline capacity, and the status of contractual commitments between the buyers and the shippers of gas. These views are summarized below.

Gas Demand Projections

The evidence generally shows agreement that demand for gas in California is expanding. The major differences between the two proponents' forecasts lie in the distribution of this demand between northern and southern California (see Section 3.1).

Altamont/Kern River Project

Altamont's principal market is southern California. Total California demand is expected to increase from 5.7 Bcf/d to 8.1 Bcf/d between 1990 and 2010, an increase of 42.5 per cent, or an average annual increase of 1.79 per cent under the assumptions adopted by Altamont. Additionally, Altamont identifies Montana, Wyoming, Colorado, Utah, Nevada, the Pacific Northwest and the US Midwest

(Chicago area) as alternate markets. Demand for gas in the above five states, currently at 1401 MMcf/d, is forecast to grow at an average annual rate of 1.7 per cent to reach 1947 MMcf/d by the year 2010. These alternate markets are currently primarily served by indigenous US supplies.

PGT Expansion Project

PGT's expansion project was originally intended to meet the needs of southern California utilities. As additional markets were identified, facilities applications were amended to include additional volumes destined to northern California. While the principal market for the PGT Expansion Project is California, some gas is intended for the Pacific Northwest. PGT's forecast of California gas demand is expected to average 5.5 Bcf/d in 1992 and to reach 7.6 Bcf/d by 2010, an increase of approximately 38 per cent, or an average annual increase of 1.85 per cent. Projected California gas requirements, as submitted by PGT, exclude directly purchased indigenous supplies (i.e., California gas production that is not received by the utilities' systems). PGT predicts that the Pacific Northwest's gas requirements will grow from 927 MMcf/d in 1992 at an average annual rate of 2% to reach 1327 MMcf/d by the year 2010. PGT believes the region already experiences a deficit in peak day capacity.

Comparison of Gas Demand Projections

Differences between Altamont and PGT forecasts of California gas requirements and the distribution of this demand between northern and southern California are depicted in the following figures (Figures 3-1, 3-2 and 3-3). Since PGT's forecast does not include total California demand, a "PGT adjusted" scenario is added to account for directly purchased California gas production that is not received by the utilities. This allows for comparison of the two forecasts on a similar basis.

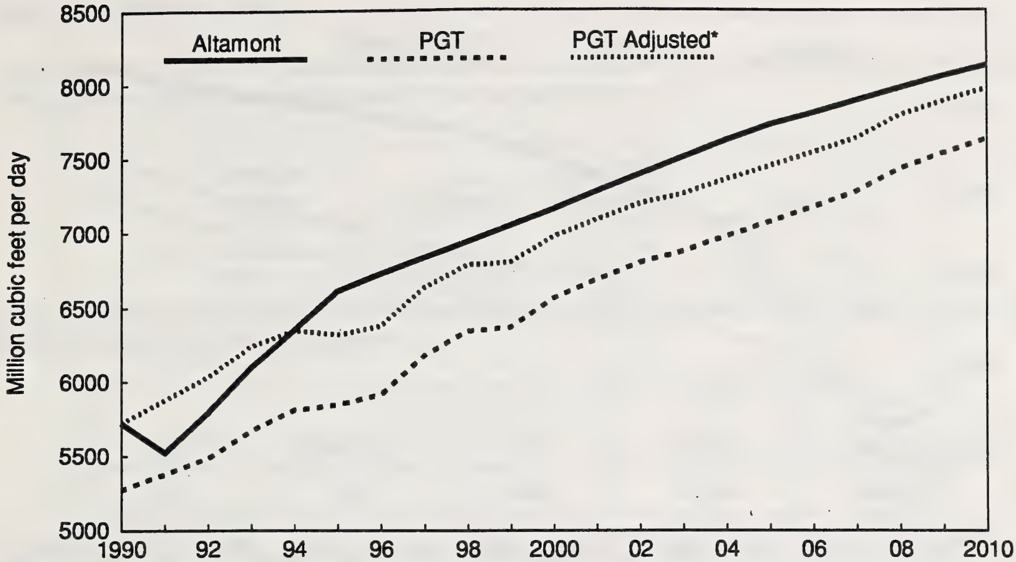
Need for Additional Pipeline Capacity into California

Altamont and PGT are in agreement that excess pipeline capacity currently exists into the southern California market, and that any incremental demand for capacity will not occur until sometime between 1995 and the year 2000. Any market captured by Canadian producers via either of the proposed projects into southern California is a displacement market over the next 5-7 years. Altamont and PGT disagree on the pipeline capacity required for northern California (see table below; Table 8-1).

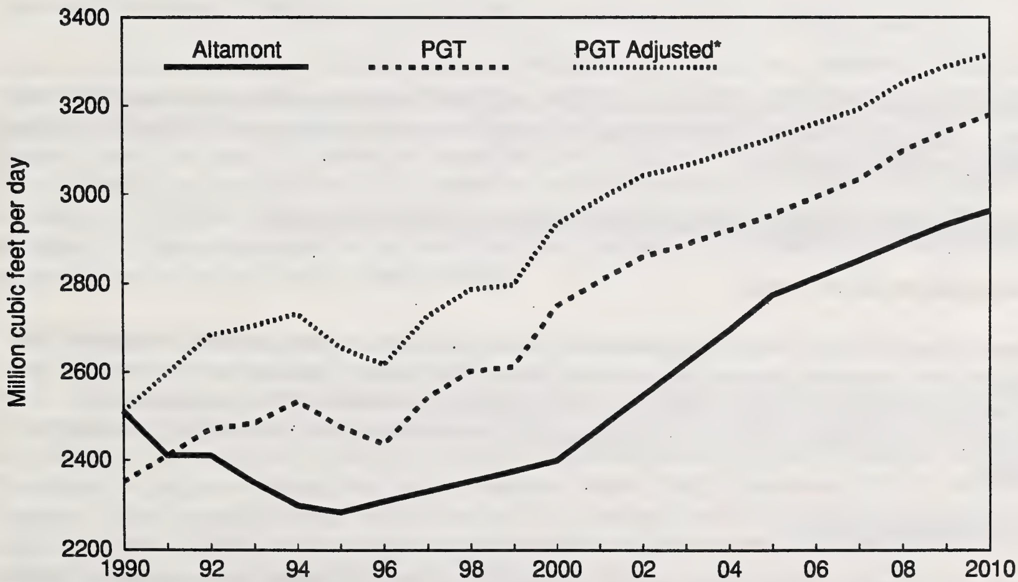
Comparison of PGT and Altamont Views on Northern California Pipeline Capacity Requirement

Projected Utilization of Current Take-Away Capacity into Northern California*				
	Forecast of Interstate Shipments (MMcf/d)		Average-Day Demand as Per cent of Existing Capacity	
	Altamont	PGT	Altamont	PGT
1992	1931	2206	90	102
1995	1875	2247	87	104
2000	2003	2538	93	117
2005	2398	2752	111	127
2010	2630	2982	122	138

*Does not include 340 MMcf/d of Transwestern and El Paso capacity additions where no take-away capability is currently available.

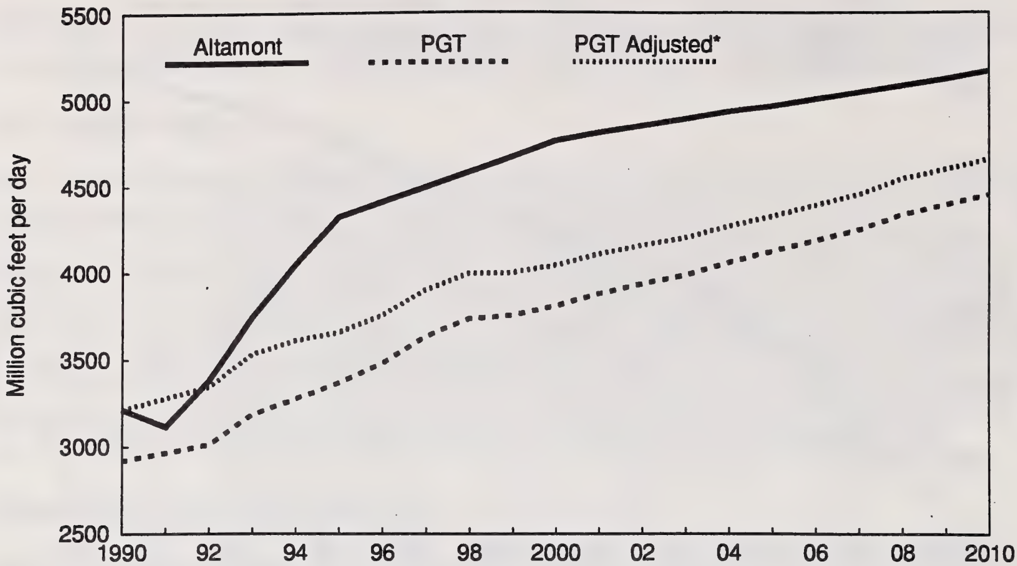


Comparison of Altamont and PGT Demand Forecasts
Total California



Comparison of Altamont and PGT Demand Forecasts
Northern California

* PGT forecast adjusted to account for direct purchases of California gas production.



Comparison of Altamont and PGT Demand Forecasts
Southern California

* PGT forecast adjusted to account for direct purchases of California gas production.

Altamont believes that no additional capacity is needed until sometime between 2000 and 2005. PGT shows a deficit from the start of its forecast period (see Section 3.3), although the deficit is a relatively small percentage through 1995.

Contractual Commitments Between Buyers And Shippers of Alberta Gas

Altamont/Kern River Project

Altamont does not expect all of the contractual commitments between end-users and shippers to be finalized until sometime closer to the in-service date of the pipeline. Altamont submits that firm end-use market contracts exist for 95 MMcf/d, and negotiations are underway for an additional 412 MMcf/d (see Section 3.4.1). No information has been submitted on the remaining proposed capacity.

PGT Expansion Project

Firm end-use market contracts exist for 448 MMcf/d and negotiations are underway for an additional 208 MMcf/d (see section 3.4.4). No information is submitted on the balance of the expanded capacity.

Costs of Proposed Facilities

Total ex-Alberta cost of the Altamont/Kern River Project is $1001.42 million (1991 C$). This cost is divided among the different components of the project as follows:

Canadian Segment	US Segment	Kern River Expansion	Total
0.336214	676.915	324.168	1001.42

Total ex-Alberta cost of the PGT Expansion Project is $1926.8 million (1991 C$) which, in turn, is subdivided into the following components:

ANG	Foothills	PGT	PG&E	Total
86	110	868.2	862.6	1926.8

Section 4.3 of the report outlines the costs of the facilities and each of the proponent's views on the projected costs of the other.

Rate Design

Altamont/Kern River Project

Under its "optional" certificate, obtained from the Federal Energy Regulatory Commission (FERC), Altamont's sponsors are held at risk for throughput shortfalls, as all fixed costs relating to return on equity and associated income taxes are recoverable through the commodity component of the pipeline's rate. This method is known as a modified fixed variable rate design. Kern River has applied for its expansion under a traditional 7(c) application but is also subject to a modified fixed variable rate design. Kern River explains that contractual obligations with shippers prohibit a change in its rate structure. The transportation rate on the total Kern River system is to be rolled-in and is expected to be lower than the rate paid on the existing system.

PGT Expansion Project

PGT's FERC certificate allows inclusion of all fixed costs in its cost-of-service and recovery through a demand charge component. This is known as a straight (full) fixed variable rate design: shippers bear the full cost of underutilization through higher unit transportation rates. For the PG&E portion of the Expansion Project, rates are regulated by the California Public Utility Commission (CPUC) and are designed using the modified fixed variable method. The National Energy Board (NEB) has approved ANG's proposed facilities with the expansion costs rolled-in with the costs of existing facilities, to be subject to straight (full) fixed variable rate design.

Ex-Alberta Transportation Rates

Altamont/Kern River Project

Transportation rates on Altamont and Kern River systems have been levelized in nominal terms so that the rate to southern California will remain constant for 13 years, thereafter declining. The following table (Table 4-5) summarizes the rates on the proposed facilities.

Altamont/Kern River Project - Ex-Alberta Transportation Rates at 100% Load Factor[1] (1991 Cdn ¢/GJ)

	1994	1995	2000	2005	2010
Altamont[2]	39.97	38.25	30.69	24.63	12.05
Kern[3]	49.42	47.29	37.95	30.45	12.62
TOTAL	89.39	85.54	68.64	55.08	24.67

Altamont anticipates new market opportunities for Alberta gas that could be reached through various pipeline interconnections stemming from the developing hub of Opal, Wyoming, particularly on an interruptible basis. Such markets could be reached at rates as outlined in the table that follows Table 4-6).

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1 While the demand and commodity rates were designed using a load factor of 95%, these are the unit rates that shippers will pay if the pipeline operates at full capacity.

2 Held constant in nominal dollars for 15 years, then declining at an average 10.6 per cent per annum.

3 Held constant in nominal dollars for 13 years, then declining at an average 11.0 per cent per annum.

Ex-Alberta Transportation Rates to non-California Markets (1993 ¢US)			
Market Served	**System**	**Interruptible ¢/Mcf**	**Firm ¢/Mcf**
Montana-Wyoming-Utah	Altamont	11	43
	TOTAL	**11**	**43**
Nevada	Altamont	11	43
	Kern River	14	53
	TOTAL	**25**	**96**
Colorado	Altamont	11	43
	Colorado Interstate	25	25
	TOTAL	**36**	**68**
Chicago	Altamont	11	N/A
	KN Energy	10	N/A
	Trailblazer	30	N/A
	NGPL	31	N/A
	TOTAL	**82**	**N/A**
Gulf Coast/Northeast US	Altamont/Kern	25	N/A
	Valero	10	N/A
	N.E. Pipeline	60	N/A
	TOTAL	**95**	**N/A**

PGT Expansion Project

The rates to northern California have been calculated under two scenarios, one assuming rolled-in rates for PG&E and the other assuming incremental rates, as shown in the following table, which also appears as Table 4-7. (For more detailed description see Section 4.5.2.1.)

Ex-Alberta Transportation
Rates for Expansion Shippers to
Northern California at 100% Load Factor
(1991 Cdn ¢/GJ)

	1994	**1995**	**2000**	**2005**	**2010**
Roll-in Rate Design for PG&E					
ANG-Foothills	6.7	6.4	5.2	4.5	3.7
PGT (Kingsgate to Malin)*	42.4	39.7	27.5	17.8	10.8
PG&E (Malin to N. California)	16.5	16.2	14.4	12.6	10.7
TOTAL	65.6	62.3	47.1	34.9	25.2
Incremental Rate Design for					
PG&E	6.7	6.4	5.2	4.5	3.7
ANG-Foothills	42.4	39.7	27.5	17.8	10.8
PGT (Kingsgate to Malin)*	43.4	39.7	28.6	19.1	11.8
PG&E (Malin to Kern)	(10.8)	(11.0)	(11.2)	(10.9)	(9.8)
Less: Credit for Backbone					
Intrastate Transmission					
TOTAL	81.7	74.8	50.1	30.5	16.5

* Based on incremental cost allocation.

Shippers to southern California intending to use the expansion facilities will be faced with paying a postage-stamp rate on ANG, mileage-based rates on PGT, and a postage-stamp rate on PG&E based on incremental rate design. These rates are summarized below (Table 4-8).

Ex-Alberta Transportation
Rates for Expansion Shippers to Southern California at 100% Load Factor
(1991 Canadian ¢GJ)

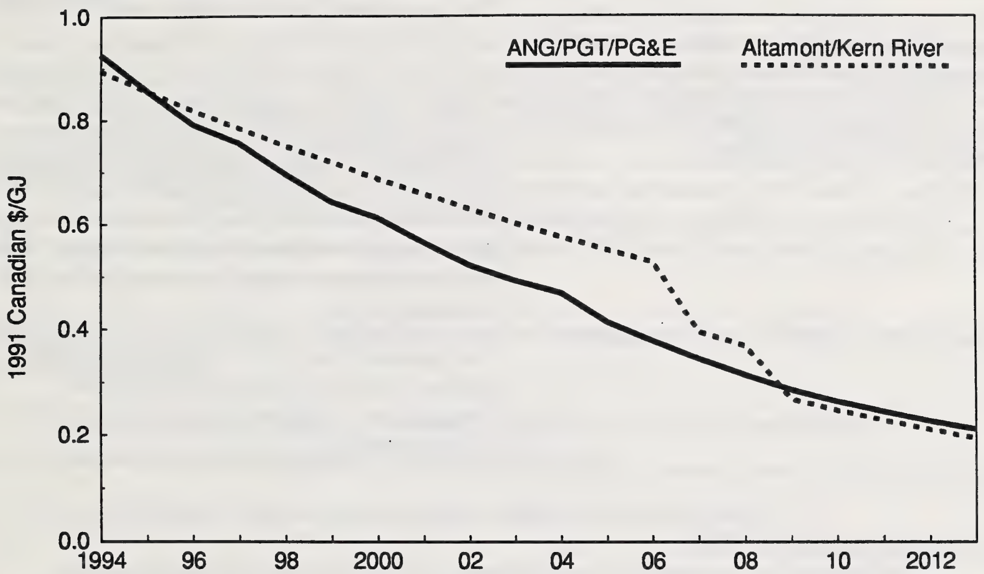
	1994	**1995**	**2000**	**2005**	**2010**
ANG-Foothills	6.7	6.4	5.2	4.5	3.7
PGT (Kingsgate to Malin)*	42.4	39.7	27.5	17.8	10.8
PG&E (Malin to K.R. Station)	43.4	39.7	28.6	19.1	11.8
TOTAL	92.5	85.8	61.3	41.4	26.3

* Based on incremental cost allocation.

Shippers serving the Pacific Northwest will be subject to a variety of transportation rates, since PGT is a mileage-based pipeline.

Comparison of Ex-Alberta Transportation Rates to Southern California

Ex-Alberta unit transportation rates for both projects operating at a 100 per cent use of capacity are shown in the following figure which also appears as Figure 4-1 (for more detailed discussion see Section 4.5). Initially, in the year 1994, Altamont's rate is marginally lower than that of PGT. Beyond 1995, PGT's is lower until beyond the year 2008, where Altamont regains a small rate advantage.



Unit Pipeline Tariffs at 100 Per Cent Capacity Utilization
Altamont/Kern River vs ANG/PGT/PG&E
Alberta Border to Southern California

Incremental rates on PGT and PG&E, rolled-in rates on ANG and Kern River.

Risks Associated With Transportation Rates

Both projects' proponents have outlined uncertainties associated with the transportation rates filed by the other. For a more detailed description of such uncertainties, the reader is referred to Section 4.4 of the report. The following summarizes some of those risks:

Altamont	PGT
FERC's impending construction rule, Order 555, may reduce the load factor that Altamont uses to calculate its rates.	Any allocation of costs on a pro-rata basis between the existing and proposed PGT/PG&E facilities would increase rates for the expansion shippers.
FERC's Order 636 may eliminate Altamont's modified fixed variable rate design in favour of a straight (full) fixed variable design.	The imposition of mileage-based rates on PG&E
Rates could be higher if Altamont's capital costs are significantly underestimated.	A take or pay surcharge could be levied on expansion shippers to cover the cost of any buy-out contracts with existing Alberta and Southern Gas Co. Ltd. (A&S) producers.
	If interruptible volumes do not materialize, PGT could try to recover these revenues thereby increasing rates.
	Very unlikely that PGT's nominal rates would decline annually as claimed, in line with depreciation. A decline every 3 years is a more likely scenario.

Intra-Alberta Pipeline Facilities

Subsequent to its filing with the Board on 17 January 1992, NOVA has revised its plans for the facilities to accommodate the PGT Expansion Project and Altamont/Kern River Project. In its 1993/94 Annual Plan submitted on 12 June 1992, NOVA indicates that the total capital expenditures for facilities proposed for the 1993/94 Gas Year including facilities to accommodate both pipeline proposals is $775 million. Another three cases were considered. One: Altamont only, the second; PGT only, the third; no California Pipeline Expansion. NOVA's expenditure under the four different cases and the associated cost-of-service impact are summarized in the following table:

Case	1993 Capital ($ Million)	1993 System Average Unit Cost-of-Service (¢/Mcf)
Both Altamont and PGT Projects as proposed.	775	28.4
Altamont only.	640	28.5
PGT only.	469	28.4
No California Pipeline Expansion.	400	28.5

Source: NOVA, 1993/94 Annual Plan, June 1992, page iv.

The majority of the costs associated with the 1993/94 facilities occur in the 1993 calendar year. As indicated in the above table, the average cost-of-service remains almost constant for that year, regardless of which scenario occurs. Chapter 5 of this report mainly summarizes NOVA's original filing. However, section 5.5 briefly describes NOVA's revised cost estimates and cost-of-service impact.

1.3 SELECTED ISSUES FACING THE PRODUCING INDUSTRY

The basic question facing producers of natural gas is whether or not they should support the provision of more pipeline capacity from Alberta to California; if so, whether one proposal, or both; if only one, which one? The answer hinges on whether producers believe the California market will be a viable long-term market, superior to the alternatives. Ideally, the answer to this question would emerge from an investigation of all opportunities potentially available to producers over time. But as is the case in all investment decisions, the future is unknown: decisions must be based on information available today. Since information on possible future markets is not available, producers are confined to reviewing the currently proposed markets. As noted above, the Board is not taking a position on these questions—they are for the industry to decide.

An assessment of new capacity, from the point of view of producers, would ideally include answers to the following questions:

- *Are the markets so reliable as to ensure a sufficient return on the investment required in production and transportation facilities to serve them?*

- *Can terms and conditions that acceptably allocate risks be negotiated?*

- *Will regulators allow recovery of costs and the required return on the investment?*

Affirmative answers to these questions should encourage private-sector decision making in favour of new capacity to California. If new capacity is desirable, the producer must then decide which pipeline to support or whether to support both. The decision to support one or both pipelines also requires information on the size and reliability of the market, the current extent and future potential of competitive supplies, the likelihood that either pipeline will actually proceed, and the implications of future regulatory decisions.

This report presents information that is intended to assist producers in making judgements related to their own interests, on the assumption that efficient private-sector decisions will ensure Alberta's interests are achieved. However, the information presented here is based on assumptions about the future that lead more or less directly to the conclusions various parties have advanced. While this report may help identify the differences in assumptions, the reader has the responsibility to assess those differences and, ultimately, to choose among them.

An example of the need for choice relates to the modelling work submitted to support the netbacks resulting from each project. The Board has not emphasized discussion of the results presented in these two studies because the assumptions underlying them are very different. But readers who are in substantive agreement with the assumptions of one or the other of these studies would no doubt find comfort in the conclusions reached. Alternately, independent studies, incorporating the reader's own assumptions about the dynamics of the market and the future commercial environment, could be

considered. The time frame and the mandate under which this report has been prepared did not allow the Board to undertake such work.

Selected Issues

Markets

The issue here for producers is whether the market opportunity justifies the long-term commitment of gas supplies at this time. The proponents present differing views on northern and southern California, as set out in sections 3.1, 3.2 and 3.3. They agree on overall growth in demand through the year 2010; but disagree on the distribution of this demand between northern and southern California. Some sectors also show disagreement about when the growth in demand would occur within the two upcoming decades. Beyond the year 2000, both agree the market will support additional capacity. As for the interval between now and 2000, some question lingers as to whether any additional pipeline capacity is needed. With respect to northern versus southern California, this question may have a different answer; but the question has relevance to both markets.

Aside from the evaluation of which proponent will be closer to the mark, producers should recognize various market risks.

- *A significantly slower rate of growth in demand in California could mean that any new capacity is operated at less than full potential. As noted in the discussion on transportation rates in section 4.5.3, when load factors decline, unit transportation rates go up dramatically.*

- *If existing supplies to this market are adequate for its needs, incremental Canadian supplies must displace them, necessitating a reduction in the market clearing price. A combination of a lower market price and higher transportation rates could make the market unattractive.*

- *If existing U.S. supplies are displaced, they may be shut in and thereafter act as a constraint limiting the potential upside of both price and volume of Canadian gas in the California market. Moreover, future low-cost supplies in the U.S. may in turn displace Canadian supplies before costs incurred by producers to access this new capacity are fully recovered. For example, there seems to be a consensus that California production will decline. However, such predictions in other regions have proven wrong. If historical production rates are partly attributable to lower gas prices, when prices firm, exploration, development, and production may all respond.*

- *Contractual arrangements may not allocate risk as appropriately as would be possible with complete information.*

- *Even if California is a good market for Canadian gas in the long term, over the next several years added capacity may be required primarily to serve periods of peak demand. New pipelines are not necessarily the most efficient way to meet peak demands, particularly when options such as increased use of storage or diversion from interruptible customers may be available.*

- *All of the above risks are magnified in the event that both pipelines proceed in the near term. Although the target markets for the two projects are somewhat distinct, opportunities for direct*

displacement or displacement through third parties are also apparent, increasing the likelihood of lower load factors on each pipeline, with consequences as described above.

As this report was being finalized for printing, Mojave Pipeline announced its intention to expand its system to run from Bakersfield in central California up to Sacremento and the eastern part of the San Francisco Bay area. Mojave claims that its expanded pipeline would result, in most cases, in a 50% reduction in the transportation cost of natural gas for northern California industries and municipalities. The proposed capacity of 300 to 400 MMcfld per day would increase competition in northern California, from either U.S. or Canadian sources. Interest in this proposal will apparently be assessed in September 1992. This report does not consider the implications of this recently announced line, but the proposal does illustrate the highly competitive nature of the California marketplace.

Ex-Alberta Pipeline Facilities

Several issues arise related to pipeline facilities outside of Alberta. They include implications the status of construction may hold for each project to meet its scheduled in-service date, the costs of each project and associated rate design issues, the likely returns available to producers, and the contractual commitments associated with the transportation requirements.

- *The fact that PGT has started construction may or may not imply that PGT is more likely to meet its scheduled in-service date. The shorter time required for construction of Altamont's project suggests uncertainty on that issue.*

- *The risk associated with cost overruns is lower for PGT, since it has a fixed-cost contract with Bechtel while Altamont has not yet completed its final engineering.*

- *Rate design issues differ for the two projects. Since Altamont is operating under an "Optional" certificate with a modified fixed variable rate design, some fixed costs are recoverable through the commodity component of the tariff. The risks to producers are set out in Section 4.4.3. Because PGT is operating under a 7(c) certificate with a straight fixed variable rate design, all fixed costs are recoverable through the demand component of the tariff. Associated risks are discussed in Section 4.4.4. Using information as filed, the Board compared rates to southern California for the two projects on a levelized basis and determined that PGT could have a rate advantage of up to 8.5 per cent. This advantage would be reduced with lower load factors, disappearing at load factors of about 50 per cent.*

- *Each of the proponents devoted considerable attention to the question of which project would provide the best netback to producers. As noted above, the Board has not emphasized these analyses because of the clear differences in the assumptions used. The approaches are described in Section 4.6. The Board leaves assessment of the assumptions to the reader. In Section 8, the Board assesses the projects on the basis of efficiency, measured in ways related to the costs of the two pipelines rather than hinging on the prices in the markets served. This assessment, based on information as filed, reveals a slight advantage for the PGT project. Again, however, the uncertainties and related risks mean these results must not be overemphasized. The differences between the projects could be eliminated or reversed by plausible changes in assumptions.*

Transportation Commitments

The strength of the commitments to transportation services on the various legs of the projects is tied to the likelihood of each project proceeding in the time frame proposed. The discussion in Section 4.7 shows that PGT and ANG have somewhat stronger commitments in place than do Altamont and Kern River. The reader must judge the significance of this fact.

The Availability of Natural Gas in Alberta

The Board has several reasons for raising the question of whether gas supply is adequate to supply one or both of the projects. One is to invite consideration of whether or not sufficient gas is or would be available to service one or both projects. Another is to elicit comment on the implications the Board's current policy and procedures respecting gas removal from the province might have for the projects and whether these policies should be altered. Another is to raise indirectly the question of whether or not the commitment of sufficient gas to service one or both pipelines to the California market would be appropriate.

That there are sufficient supplies to support one of the two projects is generally agreed. The responses also suggest that if two projects were to proceed, the Board should not interfere with the provision of supplies to either, presumably implying that policies and procedures should allow whatever commitments the industry makes. There was little comment on the implications of committing a large proportion of the province's remaining natural gas to this single market. PGT supports a total commitment, while Altamont implies that dedicating supplies to one market is not a wise choice.

The Status of Regulatory Decisions and the Issue of CPUC Control

There are two basic regulatory issues: whether the needed approvals will affect the in-service date of either pipeline; and whether the fact that PG&E's facilities in California come under the jurisdiction of the CPUC may represent a significant disadvantage not faced by Altamont. Section 7 sets out the arguments presented by the proponents. With respect to the first question, PGT's project does appear more shrouded in regulatory uncertainty (ie., Altamont's appeal in the Federal Court and the issues relating to the crossover ban). On the second question, recent activities of the CPUC do leave a reasonable presumption that, to the extent one project is more under the jurisdiction of the CPUC, Canadian producers may face greater risk.

2.0 INTRODUCTION, BACKGROUND, OBJECTIVES AND PROCESS

The Lieutenant Governor in Council, by Order in Council 715/91 dated 31 October 1991 (Appendix A), requested the ERCB to conduct a Call for Information on two proposals to construct and operate separate pipeline facilities for the removal of natural gas from Alberta to markets in the western part of the United States of America, particularly California.

One proposal would require some expansion of the NOVA system and new facilities from Empress,[d] Alberta to the Montana border. From there, the export gas would be transported to markets by a proposed pipeline of Altamont through Montana to Opal, Wyoming where it would then be transferred to an expanded Kern River pipeline system through Utah and Nevada to reach southern California (see Map 1). This proposal is referred to as the Altamont/Kern River Project.

The other proposal would receive gas from the expanded NOVA system at the Alberta-BC border near Coleman and would transport the export gas to markets by expanding existing facilities of ANG, Foothills, PGT, and PG&E in BC, Idaho, Washington, Oregon and California (see Map 1). This proposal is referred to, for the purpose of this report, as the PGT Expansion Project.

Both projects are scheduled to be in service by 1 November 1993. The Government of Alberta was concerned that the information available might be inadequate to allow producers to make rational decisions with respect to these proposals. The objective of this proceeding was to provide a forum for all interested parties to present and publicly review information relevant to the proposals to assist in their decision making. The Board was requested to summarize this information without coming to any findings or formulating any recommendations, and to submit the summary report to the Minister of Energy who will make it available to the public.

To accomplish this task, the Board issued a Schedule and Procedure and a List of Information Requested to interested parties in November 1991 (Appendix A). Seventy-six interested parties were registered as participants to this proceeding (Appendix A). Several phases of written submissions were completed and a large volume of information was filed (Appendix B). A limited oral examination of the proponents of these two projects was also carried out during the week of 23 March 1992.

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[d] Subsequent to its filing in January 1992, NOVA revised its plan for the new facilities. NOVA's expansion to accommodate Altamont will now require new facilities from Princess, Alberta to the Montana border. At the time of writing, a detailed description of such new facilities was not available.

3.0 MARKET INFORMATION

3.1 NATURAL GAS DEMAND PROJECTIONS

PGT and Altamont submitted their views on the size of the future market to be served by either pipeline. This section summarizes these views and outlines the comments that each proponent has on the other proposal, along with general Board comments on the projections.

3.1.1 Altamont Forecast of Gas Requirements

Altamont submitted a forecast of natural gas demand in California segregated by end-use category for both northern and southern California, over the period 1990-2010.[1] Altamont also included estimates of the demand for natural gas in alternate markets that could be served by its proposed pipeline.

Altamont's principal market is southern California. With modest additions to PG&E's Line 300 (see Map 1), Altamont shippers could also deliver gas to an incremental market along the southern border of PG&E's service territory. This market could also be served via direct connections between the Kern River system and individual end-users or through displacement of US southwest gas. This incremental demand stems largely from enhanced oil recovery along the southern border of PG&E's service territory and is projected by PGT to be 80 MMcf/d by the year 1994.

Altamont's projection of California gas demand recognized sources such as the California Gas Report (CGR), prepared annually by California gas utility companies, and the California Energy Commission (CEC) reports on gas and electricity. However, Altamont believes its projection is more comprehensive than the CGR because the latter excludes all demand and production not transported by California local distribution companies.

Altamont's gas demand projection is based on the assumption that California will experience annual economic growth averaging between 3 to 3.5 per cent per annum over the forecast period. It is also based on the assumption that the refinery acquisition cost of crude oil and the average field price of natural gas will increase in real terms at an average annual rate of 2.5 per cent and 3.4 per cent, respectively.

Total California gas demand is expected to increase by 42.5 per cent, from 6.17 PJ/d (5.70 Bcf/d) to 8.81 PJ/d (8.10 Bcf/d) between 1990 and 2010. Demand for gas from out of state will increase by approximately 57 per cent from 5.09 PJ/d (4.7 Bcf/d) in 1990 to 8.02 PJ/d (7.4 Bcf/d) by 2010. Altamont projects that gas demand growth in southern California will be consistently greater than that of northern California. By the end of the forecast period, southern California gas requirements will be 80 per cent higher than they are today. Northern California gas consumption is expected to decline for the next several years, rebounding only after the turn of the century, so that by 2010 northern California gas requirements are 20 per cent higher than the 1990 level.

In addition to sustained economic growth, Altamont believes that environmental regulations governing alternative fuels will play a role in increasing the long-term demand for gas in California. There is a strong incentive to use clean-burning natural gas rather than refined petroleum products in light of stringent environmental regulations in the South Coast Air Basin area consisting of Los Angeles, Orange, Riverside and San Bernardino counties.

Altamont identified the states of Montana, Wyoming, Colorado, Utah, and Nevada, which lie along the proposed pipeline's route, as alternate markets. Demand for gas in these states, which is currently at 1.52 PJ/d (1.40 Bcf/d), is forecast to grow at an annual rate of 1.7 per cent to reach 2.11 PJ/d (1.95 Bcf/d) by the year 2010.

3.1.1.1 Northern California

Total northern California gas requirements are projected to increase from 2.71 PJ/d (2.50 Bcf/d) in 1990 to 3.21 PJ/d (2.97 Bcf/d) in 2010, representing an average annual growth rate of 0.9 per cent. The gas demand forecast for northern California is summarized by sector in Tables 3-1 and 3-2 in TJ/d and MMcf/d, respectively for specific years.[e]

Table 3-1 Altamont Forecast of Northern California Gas Demand (TJ/d)*

Type of Use	1990	1995	2000	2005	2010	Avg. Annual Growth Rate (1990-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1990-2010)
Residential	640	680	700	790	870	0.92%	2.10%	1.51%
Commercial	420	470	510	550	590	1.94%	1.40%	1.67%
Industrial	540	490	490	490	490	-1.05%	0.00%	-0.53%
Non-EOR Cogeneration	140	170	180	300	310	2.72%	5.30%	4.00%
EOR**	130	140	160	180	180	2.26%	1.26%	1.76%
UEG**	740	440	460	600	680	-4.70%	4.14%	-0.38%
Other***	100	100	100	100	100	0.00%	0.00%	0.00%
TOTAL	2710	2480	2600	3010	3210	-0.41%	2.14%	0.85%

* ERCB converted data in Table C.1 Appendix 5 of 30 December 1991 submission from PJ/d to TJ/d.
** Defined on page 24 of text.
*** Included in this category; company-used gas and gas that is lost and unaccounted for.
Note: Total demand may not equal the sum of demand by sector due to rounding.

Residential gas demand as projected by Altamont is greater than that of the CGR since Altamont forecasts larger population and economic growth. Residential gas requirements are expected to grow at an average annual rate of 1.5 per cent, higher than the 0.9 per cent for total northern California.

Commercial gas requirements in northern California are projected to increase by 39 per cent over the forecast period, an average annual rate of approximately 1.7 per cent. The forecast is based on the U.S. Federal Department of Energy (DOE)-Energy Information Administration (EIA) data whose commercial category differs in definition from that of CGR.

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e Altamont provided its forecast at 5 year increments starting with 1990 to 2010, segregated by end-use category.

Table 3-2 Altamont Forecast Northern California Gas Demand (MMcf/d)*

Type of Use	1990	1995	2000	2005	2010	Avg. Annual Growth Rate (1990-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1990-2010)
Residential	593	625	650	725	800	0.92%	2.10%	1.51%
Commercial	388	430	470	510	540	1.94%	1.40%	1.67%
Industrial	500	450	450	450	450	-1.05%	0.00%	-0.53%
Non-EOR Cogeneration	130	160	170	280	285	2.72%	5.30%	4.00%
EOR**	120	130	150	170	170	2.26%	1.26%	1.76%
UEG**	680	400	420	550	630	-4.70%	4.14%	-0.38%
Other***	90	90	90	90	90	0.00%	0.00%	0.00%
TOTAL	2501	2285	2400	2775	2965	-0.41%	2.14%	0.85%

** Defined on page 24 of text.
*** Included in this category; company-used gas and gas that is lost and unaccounted for.
Note: Total demand may not equal the sum of demand by sector due to rounding.

Industrial gas demand usage is forecast to drop from 540 TJ/d (500 MMcf/d) to 490 TJ/d (450 MMcf/d) in the 5 year period (1990-1995), and is to be maintained at this level through 2010. The forecast cannot be compared to the 1991 CGR due to definitional differences and the CGR's exclusion of by-pass volumes.[f] The flat industrial demand forecast is primarily due to the changing mix of businesses in California. Altamont believes that while industrial activity will continue to increase, energy-intensive manufacturing industries are gradually being supplanted by service industries with less demand for gas or electricity. Moreover, industrial equipment will become more energy-efficient. In addition, industrial reliance on cogeneration may decrease the amount of gas needed to produce electric power.[2] While these factors tend to reduce gas demanded by the industrial sector, there are other factors that tend to increase demand such as environmental regulations, emergence of natural gas-fired vehicles and construction of desalination plants. These essentially offsetting factors, produce a flat industrial demand forecast in both northern and southern California.

Commercial and industrial non-EOR **cogeneration** gas demand is assumed to increase at an annual rate of 4.2 per cent between 1990-1995. The most rapid increase in northern California cogeneration gas demand occurs over the period 2000-2005 when the average annual increase will be 10.5 per cent. Thereafter, the increase is minuscule, so that over the forecast period annual growth rate averages about 4 per cent. The reason Altamont foresees construction of new cogeneration plants being delayed beyond the year 2000 is PG&E's strategy of trying to hold on to its customers by offering lower electric rates to discourage earlier cogeneration construction. Altamont acknowledged this is a judgement call.[3]

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f By-pass volumes are those volumes delivered to customers that do not utilize the utilities' facilities.

Altamont claims that its projection of cogeneration gas demand is based on the utility estimates presented in the 1991 CGR.[4] *[However, Table D (revised) provided in response to PG&E request no. 132, shows that the 1995 northern California cogeneration demand forecast in the 1991 CGR exceeds Altamont's projection by about 64 per cent.]*

Altamont projects a low level of **Enhanced Oil Recovery (EOR)** gas demand in northern California. Altamont argues that most EOR fields are in southern California and identifies one EOR field in the PG&E service area close to pipelines serving southern California. EOR gas demand is to increase on average about 1.76 per cent per year over the forecast period.

Electricity generation from renewable resources will expand in northern California, whereas demand for gas for **Utility Electric Generation** (UEG) is slated to decline until the turn of the century. A return to normal hydroelectric conditions will allow hydroelectricity to meet the next 9 years' growth in total electricity demand. In addition, PG&E has an opportunity to increase its purchases of low-cost hydroelectric power from the Pacific Northwest (PNW).

Altamont's forecast of UEG assumes that by 1993, normal hydroelectric generation will prevail, and that PG&E's aggressive Demand Side Management (DSM) programs will cause slower growth in electricity demand thus reducing PG&E's own gas demand for electricity generation in northern California. The assumed rate of growth of 1.9 per cent per annum electric power demand is the same as that projected in the 1990 electricity report ER 90 of the CEC. However, the utilities adjusted this rate downward by 1 to 1.5 per cent to account for DSM. Altamont's projection of UEG is based on 1.9 per cent growth after allowing for DSM. Their rationale is to ensure consistency with its assumed higher growth in the state's economy than that projected by the utilities.[5]

3.1.1.2 Southern California

Total southern California requirements for natural gas are projected to increase from 3.48 PJ/d

Table 3-3 Altamont Forecast of Southern California Gas Demand (TJ/d)*

Type of Use	1990	1995	2000	2005	2010	Avg. Annual Growth Rate (1990-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1990-2010)
Residential	900	1050	1140	1170	1190	2.37%	0.47%	1.41%
Commercial	440	490	540	610	660	2.26%	2.01%	2.13%
Industrial	530	540	540	540	540	0.16%	0.00%	0.08%
Non-EOR Cogeneration	280	330	350	360	370	2.26%	0.61%	1.43%
EOR	590	970	1030	1010	1010	5.81%	-0.21%	2.76%
UEG	620	1190	1440	1570	1700	8.84%	1.67%	5.20%
Other**	120	120	120	120	120	0.00%	0.00%	0.00%
TOTAL	3480	4690	5160	5380	5590	4.05%	0.81%	2.42%

* ERCB converted data in Table C.1 Appendix 5 of 30 December 1991 submission from PJ/d to TJ/d.
** Included in this category; company-used gas and gas that is lost and unaccounted for.
Note: Total demand may not equal the sum of demand by sector due to rounding.

Table 3-4 Altamont Forecast of Southern California Gas Demand (MMcf/d)

Type of Use	1990	1995	2000	2005	2010	Avg. Annual Growth Rate (1990-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1990-2010)
Residential	831	965	1050	1075	1100	2.37%	0.47%	1.41%
Commercial	400	450	500	560	610	2.26%	2.01%	2.13%
Industrial	492	500	500	500	500	0.16%	0.00%	0.08%
Non-EOR Cogeneration	256	300	320	330	340	2.26%	0.61%	1.43%
EOR	540	897	950	930	930	5.81%	-0.21%	2.76%
UEG	570	1100	1330	1450	1570	8.84%	1.67%	5.20%
Other**	110	110	110	110	110	0.00%	0.00%	0.00%
TOTAL	3199	4322	4760	4955	5160	4.05%	0.81%	2.42%

** Included in this category; company-used gas and gas that is lost and unaccounted for.
Note: Total demand may not equal the sum of demand by sector due to rounding.

(3.20 Bcf/d) in 1990 to 5.59 PJ/d (5.16 Bcf/d) in 2010, an average annual growth rate of 2.4 per cent. The gas demand forecast for southern California is summarized by sector in Tables 3-3 and 3-4 in TJ/d and MMcf/d, respectively, for specific years.

Altamont projects average **residential** gas requirements to increase at approximately the same rate as that of northern California (1.4 per cent per annum) yielding a higher demand level than that of the 1991 CGR mainly due to a higher forecast of population and economic growth.

The increase in **commercial** gas demand by 2010 will be 220 TJ/d (210 MMcf/d) or more than 50 per cent above the 1990 level, as compared to the 39 per cent increase over the same period for northern California. (A direct comparison of this end-use category with that of PGT is not advised since Altamont's definition of **commercial** end-use is similar to that of DOE-EIA, with components counted as industrial by CGR.) On average, commercial gas requirements increase at 2.1 per cent annually over the forecast period.

Industrial gas demand in southern California is projected to remain flat over the forecast period for the same reasons discussed earlier with regard to northern California demand. Historical industrial use, as in the case of northern California, is derived as a residual (i.e. by subtracting consumption in all other sectors from the total).

Commercial and industrial non-EOR **cogeneration** gas demand in southern California grows more slowly, in both relative and absolute terms, than in northern California, while retaining much of its initial lead. Growth in cogeneration gas demand is highest in the early years 1990-1995 at 3.2 per cent per year. Slower growth thereafter results in the average annual growth rate over the entire forecast period being a mere 1.4 per cent, which is less than the average growth rate of total southern California gas demand.

The vast majority of EOR demand is in southern California and most of these oil fields are near interstate pipelines serving southern California. Growth in gas requirements for EOR is highest over the period 1990-1995 at 10.7 per cent per year. Thereafter, EOR gas requirements grow more slowly, peaking in the year 2000 at 1030 PJ/d (950 MMcf/d). Over the forecast period, the average annual growth rate is approximately 2.8 per cent.

Altamont submits that demand for gas by UEG will almost triple over the period 1990-2010. Non-gas sources of electric power in southern California are being utilized to almost full extent with limited additional potential beyond restoration of normal hydroelectric conditions (local hydroelectric power comprises less than 5 per cent of electric generation). Environmental restrictions are motivating UEG's to burn more gas. The UEG gas requirement rises a notable 93 per cent over the initial period 1990-1995 and then grows more slowly. On average, the annual growth rate over the forecast period is 5.2 per cent.

Altamont's projection of UEG gas requirements is greater than that presented in the 1991 CGR mainly because Altamont assumed a higher economic growth and population estimates and thus higher electric demand. While Altamont used the growth projection from the electricity report of the CEC, ER 90, it assumed that growth would fully account for DSM. The utilities, on the other hand, in deriving the forecast that is reported in the CGR, assume 1.9 per cent growth in electric demand but then reduce that growth to allow for DSM, arriving at net growth over the forecast period of 1 to 1.5 per cent per year. In Altamont's view, such slow growth in electric demand would not be consistent with its economic growth rate assumption.[6]

3.1.1.3 Total California

Total California gas demand as projected by Altamont is summarized for selected years in Tables 3-5 and 3-6 in TJ/d and MMcf/d, respectively. Total gas demand in California is expected to increase by 42.5 per cent over the period 1990 to 2010, an average annual growth rate of 1.8 per cent. California gas requirement in 1990 of 6.18 PJ/d (5.7 Bcf/d) is expected to increase to 8.81 PJ/d (8.1 Bcf/d) in 2010.

Table 3-5 Altamont Forecast of Total California Gas Demand (TJ/d)

Type of Use	1990	1995	2000	2005	2010	Avg. Annual Growth Rate (1990-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1990-2010)
Residential	1540	1720	1840	1950	2060	1.79%	1.12%	1.45%
Commercial	850	950	1050	1160	1250	2.10%	1.72%	1.91%
Industrial	1000	1030	1030	1030	1030	-0.43%	0.00%	-0.22%
Non-EOR Cogeneration	420	500	530	660	680	2.41%	2.46%	2.44%
EOR	720	1110	1190	1190	1190	5.24%	0.00%	2.59%
UEG	1350	1630	1900	2170	2380	3.42%	2.31%	2.87%
Other*	220	220	220	220	220	0.00%	0.00%	0.00%
TOTAL	6180	7160	7760	8380	8810	2.31%	1.27%	1.79%

* Included in this category; company-used gas and gas that is lost and unaccounted for.

Note: Total demand may not equal the sum of demand by sector due to rounding.

Table 3-6 Altamont Forecast of Total California Gas Demand (MMcf/d)

Type of Use	1990	1995	2000	2005	2010	Avg. Annual Growth Rate (1990-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1990-2010)
Residential	1424	1590	1700	1800	1900	1.79%	1.12%	1.45%
Commercial	788	880	970	1070	1150	2.10%	1.72%	1.91%
Industrial	992	950	950	950	950	-0.43%	0.00%	-0.22%
Non-EOR Cogeneration	386	460	490	610	625	2.41%	2.46%	2.44%
EOR	660	1027	1100	1100	1100	5.24%	0.00%	2.59%
UEG	1250	1500	1750	2200	2200	3.42%	2.31%	2.87%
Other*	200	200	200	200	200	0.00%	0.00%	0.00%
TOTAL	5700	6607	7160	7130	8125	2.31%	1.27%	1.79%

* Included in this category; company-used gas and gas that is lost and unaccounted for.
Note: Total demand may not equal the sum of demand by sector due to rounding.

3.1.1.4 **Non-California Markets**

The Altamont/Kern River Project considers its shippers to be well positioned to serve markets that lie along the route of the Altamont/Kern River pipeline. The states along this route include Montana, Wyoming, Utah, Colorado and Nevada. Altamont has judged that the gas market in these states should grow from 1.40 Bcf/d in 1990 to 1.95 Bcf/d by 2010. The size of the gas market in each state and their forecast growth rates are shown in Table 3-7.

Table 3-7 Altamont Forecast of Gas Demand In Non-California Markets (MMcf/d)

State	1990	1995	2000	2005	2010	Average Annual Growth Rate 1990-2010
Montana	137	154	164	170	170	1.08%
Wyoming	153	181	196	203	203	1.42%
Colorado	630	680	720	737	737	0.79%
Utah	307	370	403	433	447	1.90%
Nevada	174	241	317	354	390	4.12%
TOTAL	1401	1626	1800	1897	1947	1.66%

Note: Total demand may not equal the sum of demand by sector due to rounding.

Altamont believes its shippers will capture around 100 MMcf/d of the gas market in these states by the year 2000, and 200 MMcf/d by 2010. Altamont claims that there are good opportunities to capture portions of the industrial and UEG markets where shippers can arrange a direct sale to an industrial

plant or electric utility. In addition sales to LDCs which are currently served by only one interstate pipeline, offer supply diversity.

With the completion of Altamont and the development of a pipeline hub at Opal, Wyoming, the Altamont sponsors are confident that shippers could also serve markets east of Colorado, particularly in the Midwest. However, these markets are largely presumed to take gas not required, on a firm basis by end-users in the principal California and mountain state markets, at off-peak times.

3.1.1.5 PGT View of Altamont Projection

The following is a summary of the comments of PGT on Altamont's gas demand projection:[7]

1. Altamont's northern California UEG forecast puts forward unsubstantiated claims regarding the northern California hydroelectric system to project lower UEG gas requirements than estimated by PG&E.

2. Additional capacity to serve the southern California market, which is the only California market Altamont is proposing to serve, will further lower the load factor on interstate pipelines serving southern California.

3. Insufficient data is provided in support statements, assumptions and conclusions.

4. There are conflicts and inconsistencies in data assumptions.

5. Altamont adopts an overly optimistic forecast of economic growth and gas demand, particularly in southern California.

6. PGT doubts that the mountain states are a viable alternative for Altamont gas as this region already produces more than 2.5 times its consumption.

3.1.2 PGT Forecast of Gas Requirements

PGT submitted that its forecast of California Gas requirements is based on the 1991 CGR.[8] However, PGT included in its projection certain demand components excluded from the CGR, namely; requirements served directly by new interstate pipeline facilities ("by-pass" volumes), and increased demand by natural gas vehicles, water desalination plants and facilities currently burning fuel oil. PGT's projection of gas requirements does not include natural gas produced in California delivered directly to end-users.

Total gas demand in California is expected to average 5.9 PJ/d (5.5 Bcf/d) in 1992, increasing by 39 per cent to 8.2 PJ/d (7.6 Bcf/d) by 2010. Imports into California are expected to increase by 44 per cent from 5.4 PJ/d (5 Bcf/d) in 1992, to 7.7 PJ/d (7.2 Bcf/d) by 2010[9], as southern California gas demand increases by approximately 47 per cent and gas demand in northern California increases by 29 per cent over the forecast period.

The forecasts for northern and southern California were developed over the forecast period 1992-2011. Current total gas consumption in PG&E's service territory, a 33 county area located in northern and central California, comprises 45 per cent of the current total California demand. Southern California is comprised of the service territory of Southern California Gas Company (SoCalGas), a 12 county

region extending from Kern County to the US-Mexican border, along with SoCalGas's wholesale customers; San Diego Gas and Electric (SDG&E) and the City of Long Beach. This accounts for 55 per cent of total gas consumption in California.

The economic assumptions underpinning the PGT projection of northern and southern California gas requirements were not specifically outlined in PGT's submission; such assumptions and indicators are presented in the 1991 CGR and its associated background documents.

The PNW is the second significant market served by PGT. The PNW is comprised of the states of Idaho, Oregon and Washington. Total gas demand in the PNW is expected to average 992 TJ/d (927 MMcf/d) in 1992. By the year 2010, gas requirements are expected to reach 1420 TJ/d (1327 MMcf/d). PGT, claiming that this region already suffers from a peak day capacity deficit, considers it particularly ripe for interstate pipeline expansion.

3.1.2.1 Northern California

Total northern California gas requirements are projected to increase from 2641 TJ/d (2468 MMcf/d) in 1992 to 3402 TJ/d (3179 MMcf/d) by the year 2010, yielding an average annual growth rate of 1.4 per cent.

The gas demand forecast for northern California is summarized by sector for specific years in Tables 3-8 and 3-9 in TJ/d and MMcf/d, respectively.

Table 3-8 PGT Forecast of Northern California Gas Demand (TJ/d)

Type of Use	1992	1995	2000	2005	2010	Avg. Annual Growth Rate (1992-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1992-2010)
Residential	596	602	636	689	760	0.81%	1.80%	1.36%
Commercial	263	282	305	325	344	1.86%	1.23%	1.51%
Industrial	502	508	654	746	774	3.36%	1.70%	2.43%
Non-EOR Cogeneration	192	281	291	299	306	5.44%	0.50%	2.67%
Total EOR	189	212	233	228	251	2.64%	0.75%	1.59%
UEG	782	646	663	698	774	-2.06%	1.57%	-0.06%
Resale-Wholesale	39	35	41	43	48	0.33%	1.48%	0.97%
NGV	1	12	33	40	45	53.61%	3.08%	23.08%
Desalination	0	0	2	2	2			
Company Use & LUAF	77	77	86	92	99	1.33%	1.52%	1.43%
TOTAL	2641	2656	2942	3162	3402	1.36%	1.46%	1.42%

Note: Total demand may not equal the sum of demand by sector due to rounding.

Table 3-9 PGT Forecast of Northern California Gas Demand (MMcf/d)

Type of Use	1992	1995	2000	2005	2010	Avg. Annual Growth Rate (1992-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1992-2010)
Residential	557	563	594	644	710	0.81%	1.80%	1.36%
Commercial	246	264	285	304	322	1.86%	1.23%	1.51%
Industrial	469	475	611	697	723	3.36%	1.70%	2.43%
Non-EOR Cogeneration	178	263	272	279	286	5.44%	0.50%	2.67%
Total EOR	177	198	218	213	235	2.64%	0.75%	1.59%
UEG	731	604	619	652	723	-2.06%	1.57%	-0.06%
Resale-Wholesale	37	32	38	41	44	0.33%	1.48%	0.97%
NGV	1	12	31	38	42	53.61%	3.08%	23.08%
Desalination	0	0	2	2	2			
Company Use & LUAF	72	72	80	86	93	1.33%	1.52%	1.43%
TOTAL	2468	2483	2750	2955	3179	1.36%	1.46%	1.42%

Note: Total demand may not equal the sum of demand by sector due to rounding.

Residential and **commercial** gas demand are projected to increase at levels slightly lower than forecast in the 1991 CGR. Residential demand is projected to grow at the same rate as total demand in northern California; at 1.4 per cent per annum. Commercial gas demand is projected to increase at a slightly higher rate of 1.5 per cent per annum throughout the forecast period.

Industrial demand consists of two components: base requirements and incremental demand due to the phase-out of fuel oil. The base requirements projection is similar to that included in the 1991 CGR, but with additional gas use due to phase-in of stricter air quality controls. Industrial fuel oil use of 143 TJ/d (134 MMcf/d) is assumed to be phased-out in equal annual decrements over a 7-year period beginning in 1996. On average, industrial demand (both core and non-core) is projected to increase at an annual rate of 2.4 per cent compared to 1.4 per cent for total northern California demand.

Commercial and industrial non-EOR **cogeneration** gas demand increases rapidly over the period 1992-1996 averaging about 10.6 per cent annually. Thereafter, the increase is less than 1 per cent which is primarily due to an increase in self-generation of electricity by industrial customers. Over the forecast period, on average cogeneration gas demand increases annually by 2.7 per cent. PGT explains the sharp rise in cogeneration gas demand over the early years of the forecast period as being due to

the addition of new Qualifying Facilities as defined in the Public Utility Regulatory Policy Act of 1978.[g] PGT's forecast of cogeneration demand is similar to that presented in the 1991 CGR.

Enhanced Oil Recovery (EOR) energy requirements are expected to peak around the year 2000 and steadily decline thereafter, due to declining oil production. EOR energy requirements could be served by local gas utilities, indigenous gas and oil supplies or by newly built interstate gas pipelines by-passing the local utility systems. Field gas serving EOR is expected to decline throughout the forecast period. Air quality regulations will result in phase-out the use of field oil as fuel by 1996. EOR demand served via by-pass (i.e. without using local distribution company facilities) is expected to increase from 27.5 per cent of total EOR gas requirement in 1992 to approximately 75 per cent by the end of the forecast period. Average annual growth of EOR gas demand is projected to be around 1.6 per cent, however, the majority of the increase occurs in the first half of the forecast period (2.64 per cent per year) rather than beyond 2000 (0.75 per cent per year). PGT's projection of EOR gas demand significantly exceeds that in the 1991 CGR since the latter excludes by-pass volumes.

Utility Electric Generation (UEG) future gas requirement is based on the 1991 CGR with an adjustment to account for the anticipation that it could take as long as 5 years to restore hydroelectric reservoirs to normal levels, even if California were to return to normal precipitation conditions beginning in the winter of 1991-1992. The amount of additional gas demand during reservoir replenishment is approximately 24.5 per cent of total UEG gas demand in 1992 or about 192 TJ/d (179 MMcf/d) declining to 7.45 per cent by 1995 and disappearing thereafter. UEG demand declines by 2 per cent annually over the nineties and rises by 1.6 per cent thereafter.

The **resale-wholesale** gas demand includes wholesale customers serving desert communities in the southern portion of PG&E's service territory. Its forecast is based on the 1991 CGR.

PGT includes in its projection gas demand for **natural gas vehicles (NGV)** over the forecast period. This category of demand is not included in the 1991 CGR. The NGV market is based on the establishment of utility NGV programs which have recently been approved by the CPUC. It is basically an incentive program to encourage purchases of NGV. Gas demand in this sector is assumed to increase from a very modest volume of 1 TJ/d (1 MMcf/d) in 1992 to 45 TJ/d (42 MMcf/d) by 2010.

PGT expects that during the next two decades, several **desalination** plants will be constructed along the state coastline that might be using modest gas volumes of 2 TJ/d (2 MMcf/d).

3.1.2.2 Southern California

Total southern California gas requirements are projected to increase from 3227 TJ/d (3016 MMcf/d) in 1992 to 4760 TJ/d (4449 MMcf/d) by 2010, an average annual growth rate of 2.2 per cent. PGT's projection of southern California demand is the sum of retail and wholesale utility-served volumes,

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[g] Qualifying facilities (QFs). Under the Public Utility Regulatory Policy Act of 1978, the electric utility company is required to purchase energy and capacity produced by QFs. The CPUC established a series of power purchase agreements which set the applicable terms, conditions and price options. The QF must meet certain performance obligations, depending on the contract, prior to receiving capacity payments. The total cost of both energy and capacity payments to QFs is recoverable in rates.

by-pass and new gas market demand such as NGVs and desalination plants. Tables 3-10 and 3-11 summarize PGT's projection by sector for specific forecast years.

Table 3-10 PGT Forecast of Southern California Gas Demand (TJ/d)

Type of Use	1992	1995	2000	2005	2010	Avg. Annual Growth Rate (1992-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1992-2010)
Residential	923	969	1002	1041	1072	1.03%	0.67%	0.83%
Commercial	304	318	341	366	396	1.46%	1.49%	1.48%
Industrial	348	415	457	461	455	3.47%	-0.05%	1.50%
Non-EOR Cogeneration	272	288	306	322	326	1.49%	0.61%	1.00%
Total EOR	621	678	753	710	730	2.45%	-0.32%	0.90%
UEG	696	837	1065	1289	1532	5.46%	3.70%	4.48%
NGV	0	4	39	103	130		12.58%	
Desalination	3	28	29	32	32		1.06%	
Company Use & LUAF	59	66	75	81	87	3.06%	1.59%	2.24%
TOTAL	3227	3603	4069	4404	4760	2.94%	1.58%	2.18%

Note: Total demand may not equal the sum of demand by sector due to rounding.

Table 3-11 PGT Forecast of Southern California Gas Demand (MMcf/d)

Type of Use	1992	1995	2000	2005	2010	Avg. Annual Growth Rate (1992-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1992-2010)
Residential	863	905	937	973	1002	1.03%	0.67%	0.83%
Commercial	284	297	319	342	370	1.46%	1.49%	1.48%
Industrial	325	388	427	431	425	3.47%	-0.05%	1.50%
Non-EOR Cogeneration	254	269	286	301	304	1.49%	0.61%	1.00%
Total EOR	580	634	704	664	682	2.45%	-0.32%	0.90%
UEG	651	782	996	1204	1433	5.46%	3.70%	4.48%
NGV	0	3	37	96	121		12.58%	
Desalination	3	26	27	30	30		1.06%	
Company Use & LUAF	55	62	70	75	82	3.06%	1.59%	2.24%
TOTAL	3016	3367	3802	4116	4449	2.94%	1.58%	2.18%

Note: Total demand may not equal the sum of demand by sector due to rounding.

Residential gas demand is projected to increase on average about 1 per cent annually. The forecast is similar to that in the 1991 CGR. The moderate growth rate in gas demand in this sector is to reflect slowing rates of migration to southern California and the influence of DSM programs mandated by the CPUC.

Commercial gas demand exhibits an annual growth rate of 1.5 per cent and is a function of growth in commercial floor space and employment in southern California. This forecast is slightly higher than what is projected in the 1991 CGR.

Industrial gas requirement can be divided into 3 components: utility, by-pass and environmentally motivated displacement of fuel oil. In 1992, utility-served industrial demand represents about 65 per cent of the total industrial requirement. This is projected to decline to 51 per cent by the end of the forecast period at an average annual rate of 1.3 per cent.

By-pass volumes constitute about 4 per cent of total industrial demand in 1992, and are projected to increase at a higher rate of 9.6 per cent per annum over the first half of the forecast period and at a much lower rate of 1.3 per cent per year thereafter. PGT reasons that by-pass volumes will only increase from 14 TJ/d (13 MMcf/d) to 36 TJ/d (34 MMcf/d) by 2010 because by-pass opportunities will be limited to those customers located near the interstate pipelines.

Industrial gas demand will increase mainly by replacing fuel oil, and will peak at 127 TJ/d (119 MMcf/d) in the year 2002.

In 1992, about 107 TJ/d (100 MMcf/d) of total industrial demand of 348 TJ/d (325 MMcf/d) is part of the core requirement. This is projected to stay relatively constant over the forecast period. The remaining industrial demand is projected to increase at an annual rate of 2.4 per cent, broadly in line with industrial demand growth in northern California.

Cogeneration gas demand is expected to grow on average 1.5 per cent per year until the year 2000. PGT believes that growth in this sector will be modest because cogeneration repurchase contracts will not be as favourable as in the past.

It is worth noting that PGT's projection of cogeneration gas requirement in northern California over the first 5 years calls for 10.6 per cent annual growth compared to a mere 2 per cent in southern California.

PGT's forecast of southern California EOR gas demand is based on the 1991 CGR but incorporates a more rapid decline in availability of field gas than assumed by SoCalGas as well as the complete phase-out of field crude combustion by 1996, due to air quality regulations.[10]

UEG is forecast to increase on average by 5.5 per cent annually over the period 1992-2000 and at a rate of 3.7 per cent over the remaining forecast period. UEG is to reach 1065 TJ/d (996 MMcf/d) by the year 2000 from 1992 levels of 696 TJ/d (651 MMcf/d).

NGV gas requirements forecast is based on an application filed with the CPUC by SoCalGas and SDG&E, adjusted for significantly lower NGV penetration rate projections, inclusion of fleet passenger car and fleet growth over time. NGV gas requirements are projected to increase from virtually zero today to 130 TJ/d (121 MMcf/d) by 2010.

Regarding **desalination** plants requirements for gas, PGT projects that by the end of the forecast period, four plants are expected to add 32 TJ/d (30 MMcf/d) of incremental gas demand.

3.1.2.3 **Total California**

Total California gas demand, as projected by PGT, is summarized for selected years in Tables 3-12 and 3-13 in TJ/d and MMcf/d, respectively. California gas requirement is expected to average 5.9 PJ/d (5.5 Bcf/d) in 1992, and to reach 8.2 PJ/d (7.6 Bcf/d) by 2010, an increase of approximately 39 per cent over the period 1992-2010, or an average annual increase of 1.9 per cent.

Table 3-12 PGT Forecast of Total California Gas Demand (TJ/d)

Type of Use	1992	1995	2000	2005	2010	Avg. Annual Growth Rate (1992-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1992-2010)
Residential	1519	1571	1638	1730	1832	0.95%	1.12%	1.04%
Commercial	566	600	646	691	740	1.65%	1.39%	1.50%
Industrial	853	916	1111	1207	1229	3.36%	1.01%	2.05%
Non-EOR Cogeneration	463	570	597	621	632	3.25%	0.56%	1.75%
Total EOR	810	890	987	938	981	2.50%	-0.05%	1.07%
UEG	1472	1477	1721	1977	2297	1.97%	2.93%	2.50%
NGV	2	16	72	143	175		9.14%	
Desalination	3	28	31	34	34		0.67%	
Other	46	41	49	52	57			
Company Use & LUAF	136	143	160	173	186	2.10%	1.50%	1.76%
TOTAL	5870	6252	7012	7566	8162	2.24%	1.53%	1.85%

Note: Total demand may not equal the sum of demand by sector due to rounding.

Table 3-13 PGT Forecast of Total California Gas Demand (MMcf/d)

Type of Use	1992	1995	2000	2005	2010	Avg. Annual Growth Rate (1992-2000)	Avg. Annual Growth Rate (2000-2010)	Avg. Annual Growth Rate (1992-2010)
Residential	1420	1468	1531	1617	1712	0.95%	1.12%	1.04%
Commercial	529	461	603	646	692	1.65%	1.39%	1.50%
Industrial	797	856	1038	1128	1148	3.36%	1.01%	2.05%
Non-EOR Cogeneration	432	532	558	580	590	3.25%	0.56%	1.75%
Total EOR	757	832	922	877	917	2.50%	-0.05%	1.07%
UEG	1376	1380	1608	1848	2147	1.97%	2.93%	2.50%
NGV	1	15	68	134	163		9.14%	
Desalination	3	26	29	31	31		0.67%	
Other	43	38	45	49	53			
Company Use & LUAF	127	134	150	162	174	2.10%	1.50%	1.76%
TOTAL	5486	5843	6552	7071	7628	2.24%	1.53%	1.85%

Note: Total demand may not equal the sum of demand by sector due to rounding.

3.1.2.4 **Pacific Northwest**

PGT predicts that the PNW gas requirements will grow from 992 TJ/d (927 MMcf/d) in 1992 to 1420 TJ/d (1327 MMcf/d) by the year 2010.[11] The states of Idaho, Oregon, and Washington are served by six major distribution utilities: Cascade Natural Gas; Northwest Natural Gas; Washington Natural Gas; Washington Water Power Company; WP Natural Gas Corporation and Intermountain Gas Company. The area is served by two interstate pipelines, Northwest and PGT, and the latter estimates that the region already experiences a peak-day capacity deficit.

To forecast gas demand in this region, PGT has aggregated the LDCs' forecasts of residential, commercial and industrial demand in their service areas, and no attempt was made to use a common forecast of fuel prices and economic growth. In addition, PGT has adjusted the LDCs' forecast of industrial demand upward to include an estimate of deliveries to industrial customers via currently authorized direct connections with Northwest, as these utility by-pass volumes are excluded from the LDCs' forecast. PGT's forecast for the electric generation sector, including both utility gas-fired construction turbines and cogeneration facilities, is based on various third party assessments which include Northwest and Westward Energy. Tables 3-14 and 3-15 summarize PGT's forecast.

Table 3-14 PGT Forecast of Pacific Northwest Gas Demand (TJ/d)

Customer Class	1992	1995	2000	2005	2010	Average Annual Growth 1992-2010
Residential	248	284	339	384	421	3.0%
Commercial	174	186	208	224	246	2.0%
Industrial	534	545	551	556	562	0.3%
Electric Gen.	30	169	176	176	176	10.3%
Other	6	7	9	12	15	5.2%
TOTAL	992	1191	1283	1352	1420	2.0%

Note: Total demand may not equal the sum of demand by sector due to rounding.

Table 3-15 PGT Forecast of Pacific Northwest Gas Demand (MMcf/d)

Customer Class	1992	1995	2000	2005	2010	Average Annual Growth 1992-2010
Residential	232	266	317	359	394	3.0%
Commercial	162	174	194	209	229	2.0%
Industrial	499	509	515	520	525	0.3%
Electric Gen.	28	158	165	165	165	10.3%
Other	5	7	9	11	14	5.2%
TOTAL	927	1113	1200	1264	1327	2.0%

Note: Total demand may not equal the sum of demand by sector due to rounding.

3.1.2.5 Altamont View of PGT Projection

The following is a summary of the comments of Altamont and its supporters on PGT's gas demand projection:[12]

1. PGT does not provide the underlying assumptions to allow making substantive comments on the forecast.

2. PGT's forecast of residential gas requirement in southern California is understated.

3. PGT sponsors do not compare their forecast with other forecasts in the public domain.

4. The gas requirements of northern California are overstated in the following areas:

    - UEG gas requirements, through the hydro lag concept and also through inclusion of the Cool Water power plant of Southern California Edison Company (SoCal Edison) in power plant load for northern California (see Map 2). While, historically, PG&E has served this plant, a pipeline off Kern River has recently been constructed to serve Cool Water. That plant is, in Altamont's view, opting for by-pass.[13]

    - The EOR demand in northern California will be met by pipelines serving southern California.

    - There is no basis for assuming that a wholesale conversion from oil to gas will occur during the next 10 years. Neither the Bay Area Air Quality Management District nor the California Air Resources Board has made such an assumption. The end result, therefore, is an overestimation of industrial gas demand.

    - The cogeneration gas requirements are overstated in northern California. They do not take into account the CPUC directives to electric utilities to offer discounted rates to consumers contemplating installation of cogeneration plants, which would tend to discourage growth of new cogeneration facilities. Moreover, PGT accounts for lower cogeneration growth in southern California because the terms for utility power repurchase contracts will become less favourable to cogenerators in future, but does not apply this assumption to cogeneration facilities in northern California.

5. Altamont contends that the PNW is more than adequately served by existing interstate pipelines. Historical data indicates that at the points of Huntingdon and Kingsgate through which Canadian gas is exported to the PNW, pipeline utilization rates have averaged less than 70 per cent so that the existing pipeline infrastructure should be able to meet growth in demand.

3.1.3 Comparison of California Gas Demand Projections

The growth in demand for natural gas in California is projected by Altamont and PGT to increase over the period 1990-2010 by 42.5 and 48.5 per cent, respectively[h] (See Figure 3-1). The major difference between the forecasts lies in the distribution of this demand between northern and southern California, as shown in Tables 3-16 and 3-17. As mentioned earlier, PGT's gas demand forecast for California excludes direct purchases of California production not delivered into the utilities system. PGT does not provide in its submission a forecast of total California supplies. Altamont's forecast of California gas production is added to the PGT projection of interstate shipments required to approximate total California demand including direct sales of indigenous supplies not received by the utilities system. This is what is referred to as the PGT adjusted demand forecast.

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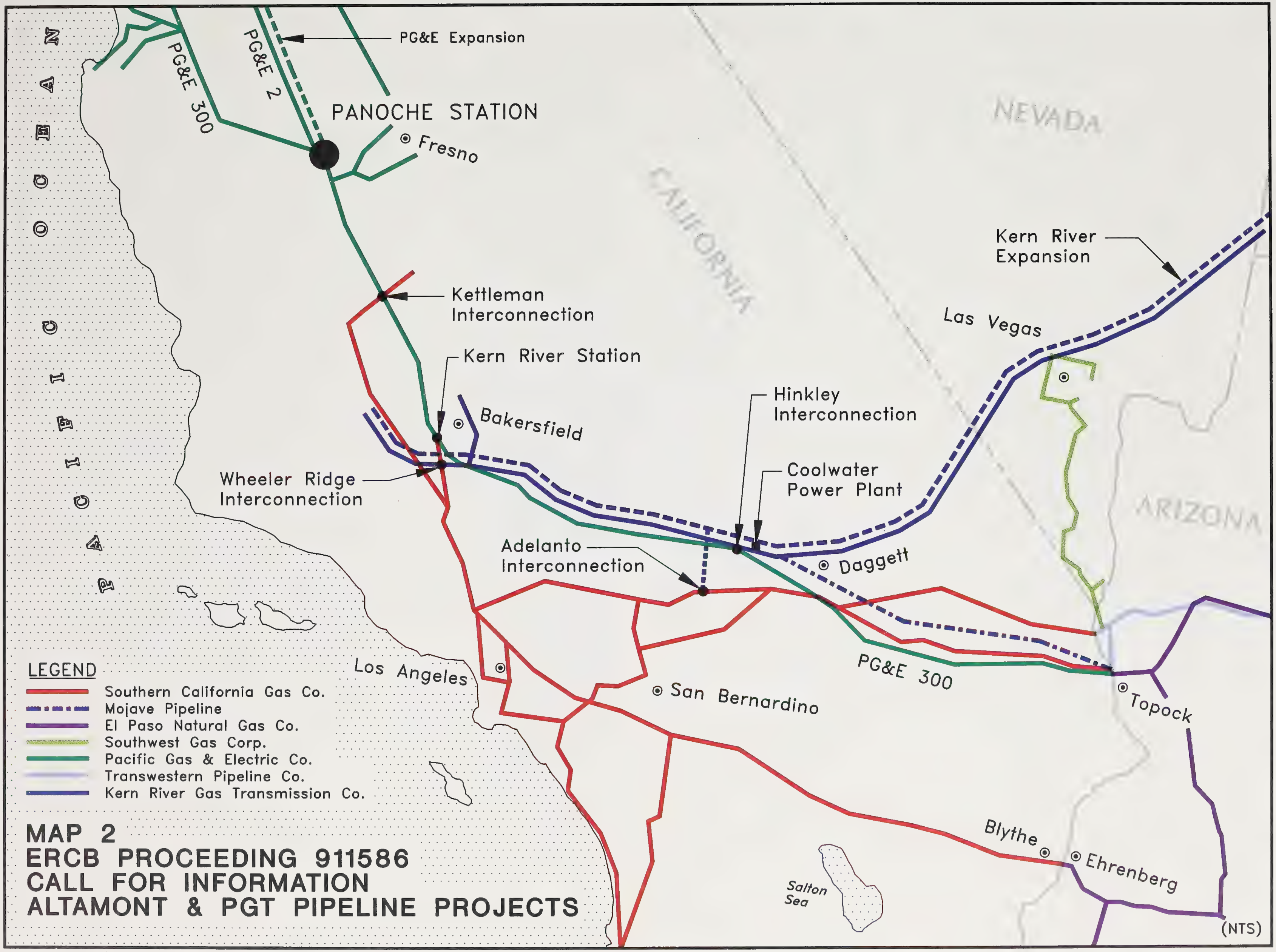
h PGT provides its forecast over the period 1992-2011. However, for the sake of comparison with Altamont's, whose projection covered 1990-2010, it is assumes the 1990 California gas consumption as reported in the CGR would be what PGT would have adopted for a 1990 actual. PGT staff confirmed that this is an appropriate assumption.



MAP 2
ERCB PROCEEDING 911586
CALL FOR INFORMATION
ALTAMONT & PGT PIPELINE PROJECTS

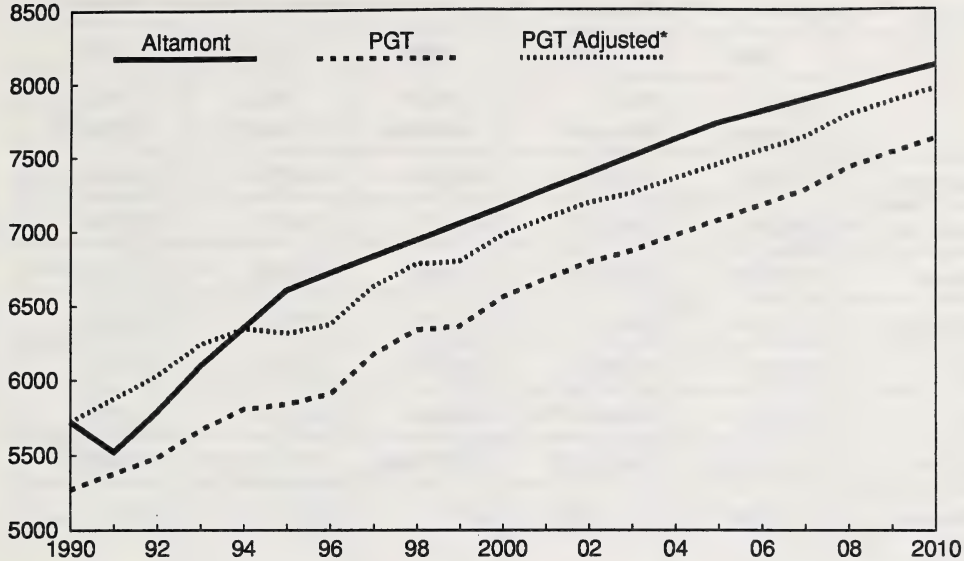


Figure 3-1 Comparison of Altamont and PGT Demand Forecasts Total California

* PGT forecast adjusted to account for direct purchases of California gas production.

The difference in the projections for northern California peaks at 350 MMcf/d in the year 2000, with PGT's projection exceeding that of Altamont. For southern California, the difference between the forecasts peaks at 958 MMcf/d for the same year, with Altamont's projection being higher. When the PGT adjusted demand forecast is considered, the margin of difference between PGT and Altamont for northern California increases to 535 MMcf/d from 350 MMcf/d in year 2000. The corresponding adjustment for southern California causes the margin of difference to fall to 726 MMcf/d from 958 MMcf/d as shown in Figures 3-2 and 3-3.

Table 3-16 Comparison of PGT/Altamont Forecasts for Northern California (MMcf/d)

	1990	1995	2000	2005	2010
	PGT/ Altamont	PGT/ Altamont	PGT/ Altamont	PGT/ Altamont	PGT/ Altamont
Residential	593/593	563/625	594/650	644/725	710/800
Commercial	250/388	264/430	285/470	304/510	322/540
Industrial	500/500	475/450	611/450	697/450	723/450
Cogeneration	127/130	263/160	272/170	279/280	286/285
EOR	99/120	198/130	218/150	213/170	235/170
UEG	680/680	604/400	619/420	652/550	723/630
TOTAL*	2321/2501	2483/2285	2750/2400	2955/2775	3179/2965
Difference between PGT/Altamont forecast	(180)	198	350	180	214

Table 3-17 Comparison of Altamont/PGT Forecasts for Southern California (MMcf/d)

	1990	1995	2000	2005	2010
	Altamont/ PGT	Altamont/ PGT	Altamont/ PGT	Altamont/ PGT	Altamont/ PGT
Residential	831/831	965/905	1050/937	1075/973	1100/1002
Commercial	400/285	450/297	500/319	560/342	610/370
Industrial	492/366	500/388	500/427	500/431	500/425
Cogeneration	256/259	300/269	320/286	330/301	340/304
EOR	540/443	897/634	950/704	930/664	930/682
UEG	570/563	1100/782	1330/996	1450/1204	1570/1433
TOTAL*	3199/2813	4322/3367	4760/3802	4955/4116	5160/4449
Difference between Altamont/PGT forecast	386	955	958	839	711

* Including others; such as company-used gas and gas lost or unaccounted for, NGV, desalination plants, wholesale-resale where applicable.

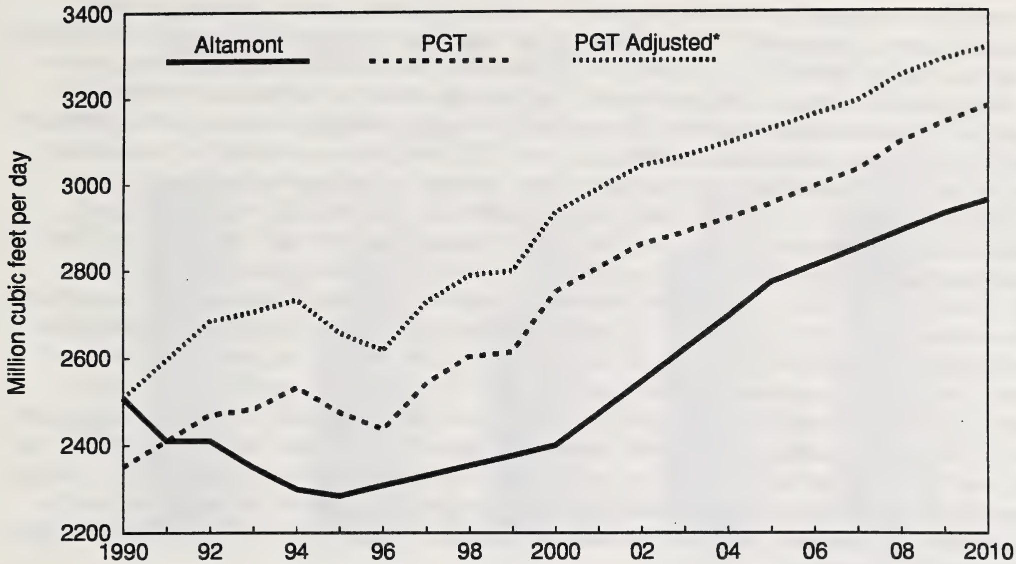


Figure 3-2 **Comparison of Altamont and PGT Demand Forecasts Northern California**

* PGT forecast adjusted to account for direct purchases of California gas production.

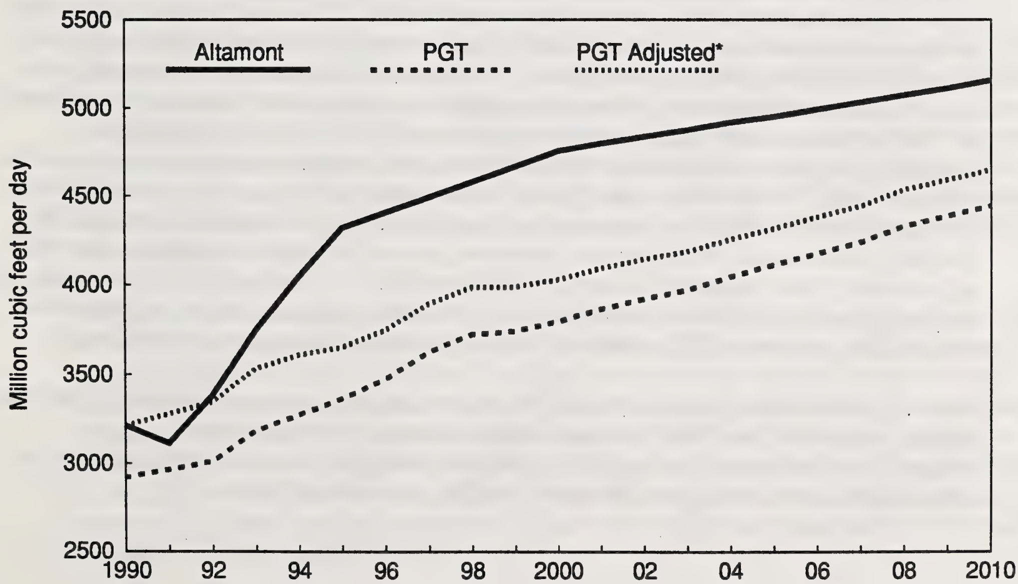


Figure 3-3 **Comparison of Altamont and PGT Demand Forecasts Southern California**

* PGT forecast adjusted to account for direct purchases of California gas production.

The Board has attempted to relate the proponents' submitted figures to those contained in three published sources of historical California data. Of the three, two incorporate all sources of production and are in close agreement: The CEC and the US DOE-EIA. The CGR includes neither the sources nor the dispositions of natural gas produced in California for direct sale to end users unless it is transported by gas distribution utilities. The one publication that attempts to capture both sources and dispositions of locally-produced direct sale gas is the CEC; but it does not attempt to balance total supply of gas to California and total end use. In 1989, its most recent reported year, end uses of 5190 MMcf/d amount to only 93 per cent of the 5568 MMcf/d, which the CEC recorded as total supply. An allowance of almost 7 per cent for inventory changes, pipeline fuel, gas plant fuel, losses and adjustments in a state that depends on imports for some 85 per cent of its supply may be too large. The Board, therefore, concurs with Altamont's objective in adjusting historical end uses upward to be consistent with DOE's figure of 5727 MMcf/d for total gas supply to California in 1990. Since no statistical source appears to account for all of the state's end use, the assignment of a residual amount to end-use categories is necessarily judgemental. For this reason, it might not be wise to compare the forecast submitted by the pipeline proponents to that of the CEC projection in its totality. However, it might be useful to compare the proponents' forecasts with that of the CEC[i] in three areas where most of the growth in California gas requirements is expected to occur, namely UEG, EOR and Cogeneration. What follows is a short description of the main differences in the two projections for both northern and southern California and how they compare to that of the CEC for the sectors where most growth is anticipated.

Northern California

- *The most significant difference between the Altamont and PGT forecasts stems from differing views of demand by UEG. PGT predicts approximately 200 MMcf/d of additional UEG gas demand up to the year 2000. Altamont does not agree with PGT's assumption that if weather conditions do return to normal it could take up to 5 years to restore hydroelectric reservoirs to normal conditions because of abnormally low reservoir levels (this delay is termed hydro-lag). The disagreement here explains the large difference between the forecasts. The difference in UEG gas requirements starts declining beyond year 2000, but PGT's projection is consistently higher than Altamont's. This could stem from Altamont's assumption of successful DSM by PG&E, which dampens the effect of its more optimistic economic growth assumption (3% versus 1.2 to 1.5% of real growth as per the 1991 CGR). PGT explains that the CGR or the CEC do not include this hydro-lag component because the utilities are obliged to provide a forecast as if they experience a normal hydro year. PGT, in its submission to the Board, was not constrained to assume a normal hydro year, but rather based its forecast on what actual demand has been in the UEG system and what it is likely to be over the forecast period.*

  Note that Altamont's projection of UEG in northern California is consistently lower than what PG&E projected in the 1991 CGR; and while it is consistent with the recent projection by CEC up to the year 2000, thereafter, Altamont's forecast is lower than that of CEC. The forecasts diverge by 181 MMcf/d in 2010, as shown in Figure 3-4.

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i CEC, 1991 Fuels Working Paper: *Natural Gas Market Outlook*, December 1991.

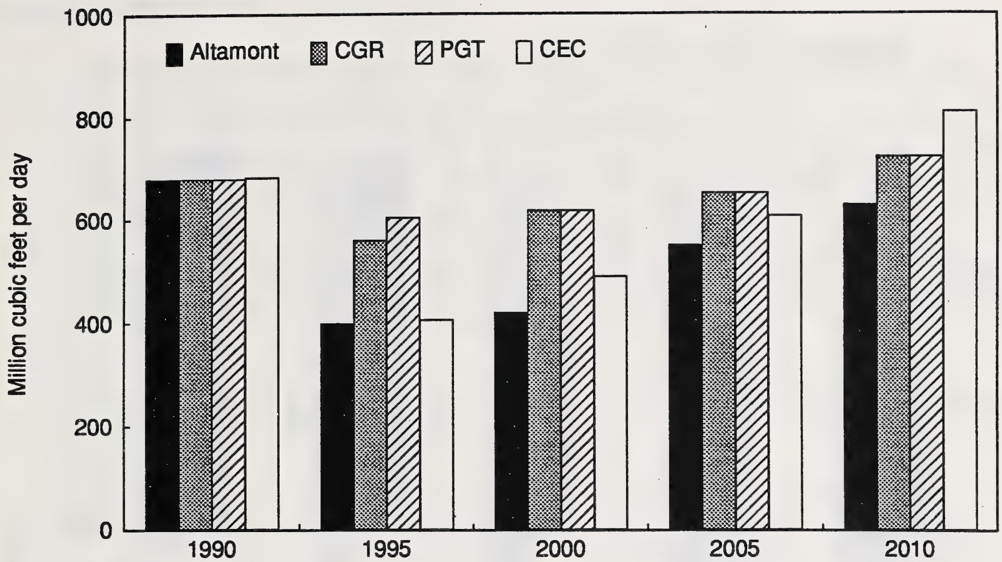


Figure 3-4 Comparison of UEG Demand Forecasts Northern California

- *PGT predicts a significant increase in non-EOR cogeneration demand over 1992-1996, averaging 10.6 per cent annually. Altamont delays this increase to the period 2000-2005, beyond which both projections are similar. The difference in cogeneration gas requirements accounts for approximately 100 MMcf/d of the difference in total northern California demand as projected by PGT and Altamont. Altamont says the significant difference in timing of any incremental requirement by cogeneration is a judgement call. Note that Altamont's projection is consistently and significantly lower than that provided in the recent CEC forecast. As a matter of fact, even PGT's projection is lower than that of the CEC. The difference between the Altamont and the CEC outlooks peaks at approximately 180 MMcf/d by the year 2000, as shown in Figure 3-5.*

- *The gas requirements for EOR schemes located in northern California, even though they are served by interstate pipelines serving southern California, are assumed by PGT to be part of northern California demand. Altamont considers that since most oil fields are in southern California, the majority of EOR demand will be part of southern California gas consumption, including those fields that are geographically located in northern California but, are to be served by Kern River. The difference in EOR gas requirements accounts for 40 to 60 MMcf/d of the difference in total northern California demand as projected by PGT and Altamont. A comparison of both forecasts to that of CEC indicates that both are significantly higher than the latter, as shown in Figure 3-6.*

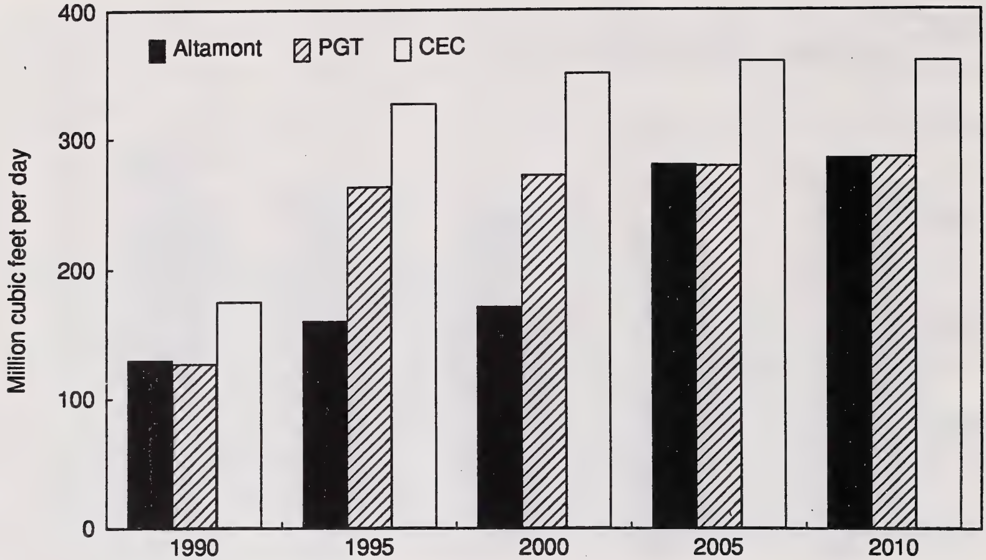


Figure 3-5 **Comparison of Non-EOR Cogeneration Demand Forecasts Northern California**

* CGR forecast omitted as it does not include by-pass volumes.

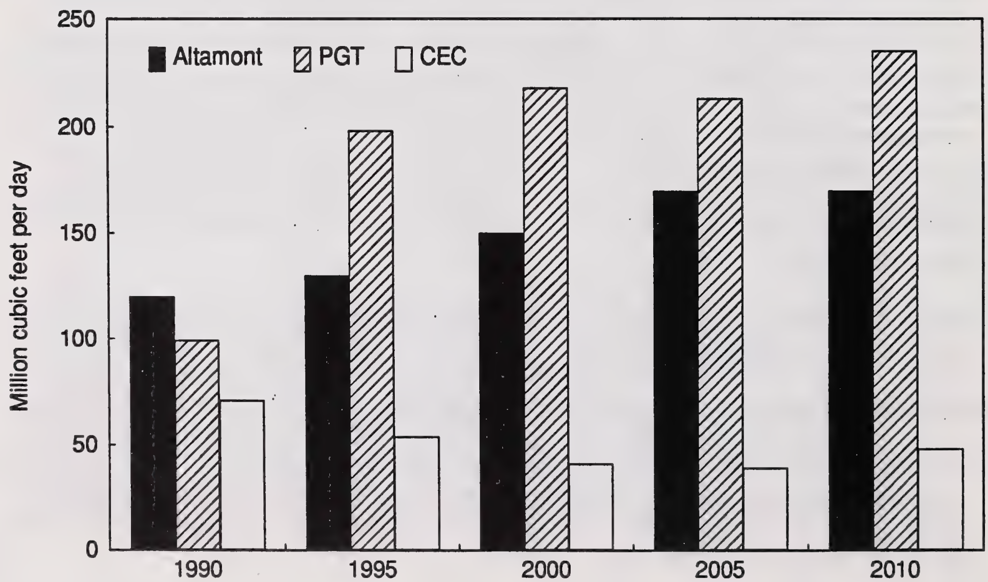


Figure 3-6 **Comparison of EOR Demand Forecasts Northern California**

* CGR forecast omitted as it does not include by-pass volumes.

Southern California

- *The difference between Altamont and PGT forecasts of UEG gas requirements peaks at 334 MMcf/d by the year 2000; thereafter, it declines to 137 MMcf/d by 2010. Most of the increase in gas demand by UEG, according to Altamont, occurs over the earlier period, 1990-1995. While the projections have similar average annual growth rates over the forecast period, PGT's projection reflects a more steady, continuous growth rather than an immediate increase over the short-term. Both forecasts are higher than that of the CEC, as shown in Figure 3-7. Altamont's projection is higher than PGT's, mainly because of a higher economic growth rate and also possibly because of the inclusion of the Cool Water Power Plant of SoCal Edison. That plant is currently being served by PG&E but is likely to opt for by-pass, becoming part of the southern California load.*

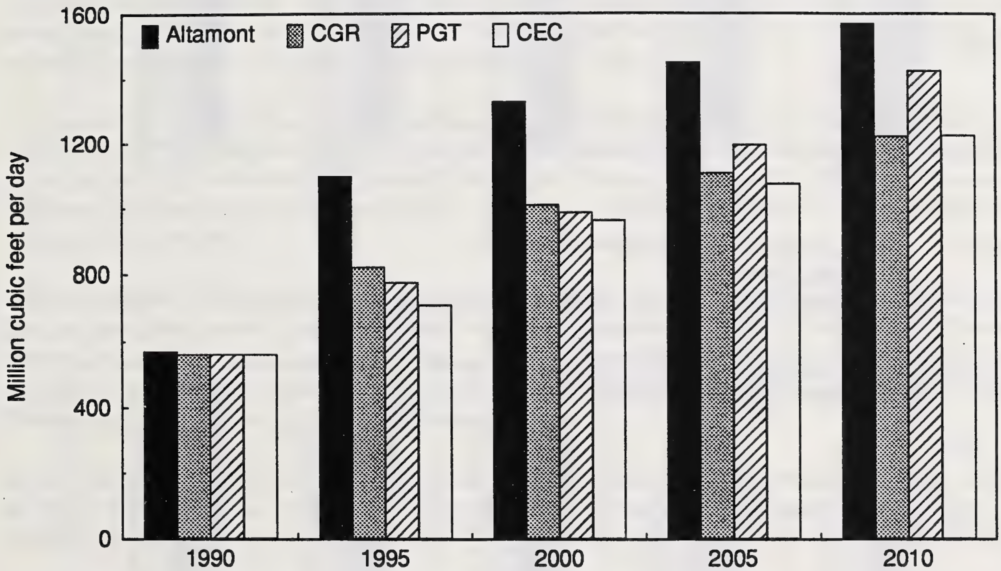


Figure 3-7 Comparison of UEG Demand Forecasts Southern California

- *Altamont's forecast of EOR demand exceeds that of PGT on average by 250 MMcf/d. PGT's forecast of EOR demand is also lower than that projected by the CEC (see Figure 3-8). Altamont's average annual growth rate over the period 1990-2010 is 2.76 per cent, compared to the 2.74 per cent in the CEC projection. PGT's annual average growth rate of EOR demand in southern California is approximately 2.18 per cent.*

- *Altamont's forecast of non-EOR cogeneration gas requirements accounts for approximately 30 MMcf/d of the total incremental requirements projected by Altamont for southern California. Whereas Altamont expects cogeneration gas demand to grow on average by 1.43 per cent over the forecast period, the CEC and PGT forecast similar annual average growth rates of approximately 0.9 per cent (see Figure 3-9).*

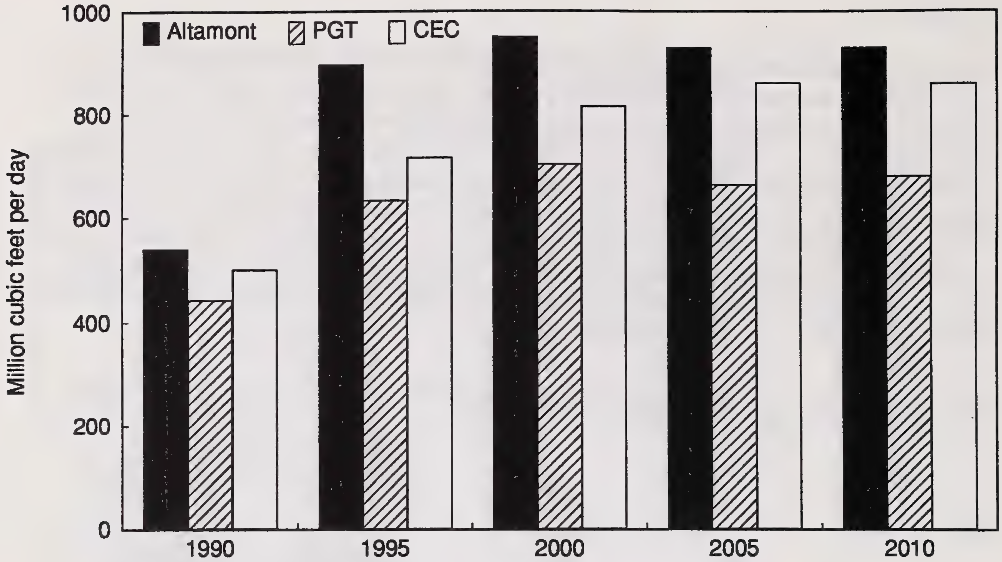


Figure 3-8 **Comparison of EOR Demand Forecasts**
Southern California

* CGR forecast omitted as it does not include by-pass volumes.

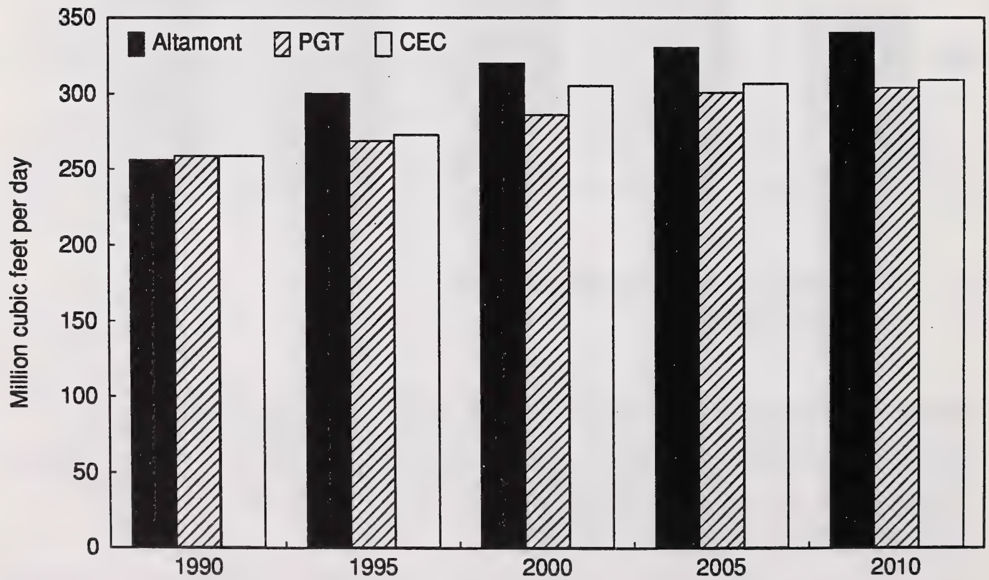


Figure 3-9 **Comparison of Non-EOR Cogeneration Demand Forecasts**
Southern California

* CGR forecast omitted as it does not include by-pass volumes.

3.1.4 General Comments on the Forecasts

PGT's projection, as summarized in this report, is based on the PG&E and SoCalGas's submissions to the CGR. Those submissions are based on different assumptions about future oil and gas prices. PG&E's submission to the CGR assumes that the Refiners Acquisition Costs of Crude (RACC) will increase at a real rate of 2.4 per cent per year from 1994 to 2010. SoCalGas assumes that the RACC increases at a real rate of 4.2 per cent per year over the same period. The PG&E projection of northern California demand assumes that average gas prices in the system will rise at a real annual growth rate of approximately 1.4 per cent, whereas SoCalGas assumed average gas rates increasing at 2.4 per cent. PGT's forecasts for northern and southern California are based on differing assumptions, which raises questions of consistency. Similarly, demand projections for the Pacific Northwest obtained from the six different utilities serving that region, present varied outlooks on future gas prices. PGT did not attempt to adjust the forecast of gas requirements to reflect one particular view of expected gas prices. That means there is a disadvantage with respect to consistency that must be weighed against the advantage inherent in having projections developed by the LDCs that serve the individual regions and are therefore most knowledgeable about them.

In its projection, PGT does not include demand from indigenous supplies that are not received by the utilities system. This omission creates a problem in forecasting future demand for interstate shipments, given that the total requirement is generally projected to increase, whereas the consensus is that California gas production has matured and is expected to decline in the future (this expectation is also a source of uncertainty).

Altamont's method of forecasting future requirements for gas in California implicitly considers factors such as population growth, economic growth and price projections. However, no explicit relationship between the various factors can be scrutinized, since Altamont did not employ a macroeconomic model to project requirements. Altamont's forecast, based on judgement and intuition, is difficult to assess. However, it can be subjected to a test of reasonableness.

While economic growth in California has exceeded that of the nation, the reader must judge whether the evidence presented supports a 3 to 3.5 per cent growth rate over the forecast period. Lower growth in population and the economy would suggest lower growth in the demand for natural gas.

Similarly, the reader should assess Altamont's projection of gas requirements for UEG. These requirements in southern California are projected to grow at about twice the rate projected by the utilities over the period 1990-1995. If one accepts the underlying assumptions about the economy, one must then decide whether that justifies significantly higher growth in the use of gas by electric utilities than those utilities themselves are projecting.

3.2 EXISTING PIPELINE CAPACITY AVAILABILITY

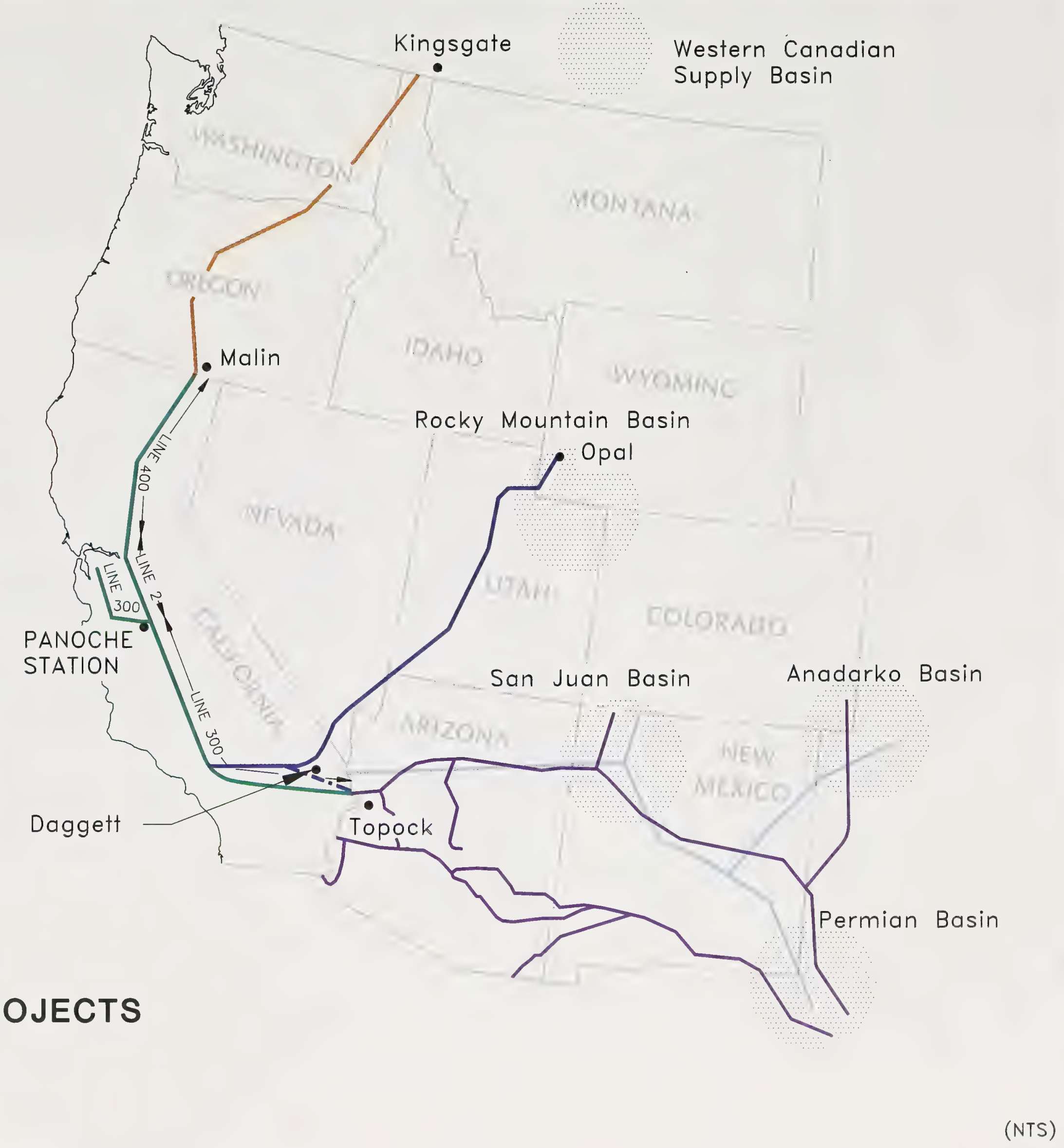
3.2.1 Northern California

Current interstate pipeline capacity into northern California totals 2160 MMcf/d (see Map 3). The PGT system, which interconnects with PG&E at Malin, Oregon, has a current capacity of 1020 MMcf/d. The El Paso Natural Gas Co. (El Paso), connecting with PGE's Line 300, is currently capable of delivering 1140 MMcf/d to PG&E to serve northern California.

California Interstate Pipeline Capacities (MMcf/d)

	Capacity
North	
PGT	1020
El Paso	1140
Total	2160
South	Capacity
El Paso	1950 (400)*
Transwestern	750 (340)*
Kern River	700
Mojave	400
Total	3800 (4200)*

*Capacities which have recently come on stream. However, out of 740 MMcf/d there is take away capacity of only 400 MMcf/d.



LEGEND

- Pacific Gas Transmission Co.
- Pacific Gas & Electric Co.
- Kern River Gas Transmission Co.
- Transwestern Pipeline Co.
- El Paso Natural Gas Co.
- Mojave Pipeline

MAP 3
ERCB PROCEEDING 911586
CALL FOR INFORMATION
ALTAMONT & PGT PIPELINE PROJECTS

ERCB

3.2.2 Southern California

Existing interstate capacity into southern California is 3800 MMcf/d[j] (see Map 3). The El Paso system and Transwestern Pipeline Co. (Transwestern) are capable of delivering up to 1950 and 750 MMcf/d respectively into the SoCalGas system. Kern River and Mojave, which have recently been commissioned, have capacities of 700 and 400 MMcf/d, respectively. Recently, El Paso has expanded its system by 400 MMcf/d (1 April 1992) and similarly Transwestern expanded by 340 MMcf/d (1 March 1992). However, there is currently take-away capacity at the California border for only 400 MMcf/d of this expansion.

3.3 INTERSTATE GAS PIPELINE CAPACITY PROJECTION

3.3.1 Altamont Forecast of Pipeline Capacity Requirements

Altamont's forecast of interstate shipments into northern and southern California increases over time as gas demand increases and indigenous supplies decline. It shows a California gas production decline at an annual average rate of 1.24 per cent, over the forecast period. California production declines more rapidly over the period 1992-1995 when the annual decline rate is approximately 2 per cent. Altamont's forecast of interstate shipments required to meet future California demand is summarized in Table 3-18.[14]

Table 3-18 Altamont Forecast of Interstate Shipments

MMcf/d	1992	1995	2000	2005	2010
Northern California:					
Demand	2411	2285	2400	2775	2965
California Production	480	410	397	377	335
Interstate Shipment	1931	1875	2003	2398	2630
Southern California:					
Demand	3386	4322	4760	4955	5160
California Production	505	475	462	441	398
Interstate Shipment	2881	3847	4298	4514	4762
Total California:					
Demand	5797	6607	7160	7730	8125
California Production	985	885	859	818	733
Interstate Shipment	4812	5722	6301	6912	7392

Altamont compares pipeline capacity over the period 1995-2010 to interstate shipments required in order to arrive at projected capacity additions.[15] The results are summarized in Tables 3-19 and 3-20 for northern and southern California, respectively.

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j 1991 California Gas Report.

Table 3-19 Altamont Comparison of Interstate Shipments Required Into Northern California With Proposed Pipeline Capacity (Bcf/d)

	P/L Capacity Without Both Proposed Projects*	P/L Capacity With Altamont Only	P/L Capacity With PGT Only	P/L Capacity With Both Proposed Projects	Average Demand for Interstate Shipments
1995	2.4	2.4	2.6	2.6	1.9
2000	2.4	2.4	2.6	2.6	2.0
2005	2.4	2.4	2.6	2.6	2.4
2010	2.4	2.4	2.6	2.6	2.6

* This includes currently available capacity into northern California plus recently added Transwestern capacity from the San Juan Basin, even though currently there is no tie-in capacity to California for all the Transwestern volumes.

Table 3-20 Altamont Comparison of Interstate Shipments Required Into Southern California With Proposed Pipeline Capacity (Bcf/d)

	P/L Capacity Without Both Proposed Projects*	P/L Capacity With Altamont Only	P/L Capacity With PGT Only	P/L Capacity With Both Proposed Projects	Average Demand for Interstate Shipments
1995	4	4.4	4.4	4.9	3.8
2000	4	4.4	4.4	4.9	4.3
2005	4	4.4	4.4	4.9	4.5
2010	4	4.4	4.4	4.9	4.8

* This includes currently available capacity into northern California plus recently added Transwestern capacity from the San Juan Basin, even though currently there is no tie-in capacity to California for all the Transwestern volumes.

As the tables indicate, Altamont believes that the PGT Expansion Project will result in considerable excess capacity into northern California whereas building Altamont, while it does not add to idle capacity in northern California, will meet the requirement for additional capacity in southern California past the year 1995.

Altamont states that firm transportation peaking needs can be met through utilization of existing pipeline and storage capacity. Therefore, unlike PGT, Altamont does not add capacity inflators to interstate demand. Also, unlike PGT, Altamont assumes that Transwestern capacity of 340 MMcf/d from the San Juan Basin, while it is not tied to California utilities, indeed is part of existing capacity because demand will cause this capacity to be tied to the utilities. Altamont remarks that expanding PG&E Line 300 to make additional capacity available is now subject to CPUC investigation into alternate methods of increasing the availability of natural gas in California. The expansion of storage capacity is another option.[16]

As is evident from Table 3-19, Altamont does not agree with PGT that capacity into northern California is currently deficient. Even if such capacity limitations do exist, Altamont is of the view that they are remediable. Storage capacity in California is among the least cost in the country and strategically located in relation to market. It is Altamont's opinion that current storage capacity at McDonald Island could double by adding compression and some injection wells.[17] Altamont notes that at one point, PG&E had an application in front of the CPUC to expand storage capabilities at McDonald Island; but that was recently withdrawn without explanation. With the start-up of Kern River, Altamont is of the view that PG&E will lose part of its load to by-pass opportunities, freeing up 200 to 400 MMcf/d of capacity which, together with expanded storage capacity at McDonald Island, would be adequate to meet peak requirements.[18]

As Table 3-20 indicates, Altamont also believes that southern California does not suffer from any capacity deficiency at the present time. Market demand dictates that sometime over the period 1995-2000 additional capacity will be required. Therefore, in the short-term, markets in southern California for either proposed pipeline are essentially displacement markets. In other words, there would not be an immediate incremental market for all of the capacity on all of Altamont's proposed 719 MMcf/d pipeline or on PGT's 755 MMcf/d expansion.

Altamont points out that approximately 400 MMcf/d of its total proposed volumes, for which market arrangements are finalized or in the process of being negotiated, are being supplied by other producing areas and constitute a displacement market. However, it is confident that with this level of volume commitment the project could go ahead. Out of the 400 MMcf/d, approximately 350 MMcf/d is in southern California. Altamont anticipates that gas requirements in this region will grow on average by 100 MMcf/d annually and, therefore, expects to serve part of that incremental demand over the next 3 to 7 years. So, while there is no urgent, immediate demand in the marketplace, Altamont is still prepared to go ahead to position itself to capture a share of future market growth.

In summary, Altamont is of the view that there does not exist sufficient incremental gas demand in California to support either of the proposed projects in the next few years. If both projects go ahead, Altamont concedes that there will be some price discounting since part of the service provided by the proposed pipelines over the next few years will be interruptible. It would take up to 7 years to fill either of the proposed projects with incremental gas requirement.

3.3.2 PGT Forecast of Pipeline Capacity Requirements

PGT expects the gas pipeline capacity required to be over 6.3 PJ/d (5.9 Bcf/d) in 1992. Needed capacity is projected to increase to 9.0 PJ/d (8.4 Bcf/d) by 2010.[19] PGT defines the capacity requirement to be the sum of the interstate supply requirement and additional capacity reservations. Northern California supply imbalances will become more pressing than those in southern California. In PGT's view, pipeline additions should have the flexibility to address northern California's need for capacity additions.

Subtracting in-state supplies from demand results in California's need for out of state gas supplies. Capacity reservation depends on that and three additional factors. The first, a core market capacity reservation, meets a CPUC requirement that utility reservations are to be based on core market requirements in the peak month of an average temperature year. In northern California, for example, this reservation is 41 per cent per day greater than the 1995 daily core requirements. The second, non-core capacity reservations, is an allowance for peaking needs and future growth in fuel requirements of end-users. The third, is frictional pipeline capacity, which is the amount of capacity available for brokering that is likely to be on the market at any given time.

The PGT forecast of interstate shipments required to meet future California demand is provided in Table 3-21.[20]

Table 3-21 PGT Forecast of Interstate Shipments

MMcf/d	1992	1995	2000	2005	2010
Northern California:					
Demand	2471	2476	2751	2956	3180
Northern California Production	265	229	213	204	198
Interstate Shipments	2206	2247	2538	2752	2982
Southern California:					
Demand	3016	3367	3802	4115	4448
Southern California Production	171	184	230	237	196
Interstate Shipments	2845	3183	3572	3878	4252
Total California:					
Demand	5487	5843	6553	7071	7628
California Production*	436	413	443	441	394
Interstate Shipment	5051	5430	6110	6630	7234

* PGT accounts for only California production received by the utilities.

PGT views interstate shipments into either northern or southern California as the way to replace declining California gas production. The utilities' purchase of indigenous supplies declines at an average annual rate of 0.5 per cent over the forecast period, but the decline rate is significantly higher from 1992 to 1995 at 1.8 per cent per annum.

Tables 3-22 and 3-23 summarize pipeline capacity requirements into northern and southern California.[21] PGT does not include in existing pipeline capacity, the 340 MMcf/d addition by Transwestern and El Paso for which no take-away capacity is planned by PG&E. It is PGT's view that the price of this new supply does not economically justify additional facilities by the utility to receive this gas.[22]

Table 3-22 PGT Interstate Capacity Requirement As Compared To Existing Capacity Into Northern California (Bcf/d)

	P/L Capacity Without Proposed Projects	Interstate Shipments Required	Additional Capacity Reservation	Total Capacity Requirement
1995	2.16	2.2	.6	2.8
2000	2.16	2.5	.6	3.1
2005	2.16	2.8	.6	3.1
2010	2.16	3.0	.6	3.7

Table 3-23 PGT Interstate Capacity Requirement As Compared To Existing Capacity Into Southern California (Bcf/d)

	P/L Capacity Without Proposed Projects	Interstate Shipments Required	Additional Capacity Reservation	Total Capacity Requirement
1995	3.8	3.2	.4	3.6
2000	3.8	3.6	.4	4.0
2005	3.8	3.9	.4	4.3
2010	3.8	4.2	.5	4.7

Additional capacity reservation in Table 3-22 is the sum of 41 per cent of core demand, 12.5 per cent of non-core demand, and 1 per cent of non-core demand. The latter represents frictional capacity, which is the difference between required firm capacity and average daily throughput on interstate pipelines. The additional core reservation capacity is net of PG&E's existing storage facilities and purchases of California supplies.[23] PGT explains that for PG&E, the CPUC has approved a core market reservation which is 41 per cent greater than the projected daily core requirements for the year 1995. The weighted average non-core reservation factor equals 125 per cent, which is the ratio of peak month to average month daily demand in 1992. To be conservative, PGT uses 12.5 per cent of non-core as part of the additional capacity reservation rather than the full 25 per cent.[24] The resulting capacity requirement is almost 25 per cent higher than average daily throughput. Table 3-22 shows that, under PGT's assumptions about the demand for natural gas and the capacity required to deliver it, there is a capacity deficit in northern California as of 1992 and thereafter. This conclusion supports its proposed expansion to meet the need for additional capacity.

Even with the proposed 250 MMcf/d expansion into northern California, PGT is projecting a deficiency in capacity required over the forecast period. This deficiency ranges from 595 MMcf/d in 1992 to 1273 MMcf/d by the year 2010, after accounting for current storage capabilities. However, PGT concedes that this capacity might not be required on an average daily basis but that it is required for peaking purposes.

The additional capacity reservation in southern California as projected in Table 3-23, is the sum of the SoCalGas' core market reservation, which is 10.7 per cent of core demand, plus 11 per cent of non-core demand, and 1 per cent of non-core demand representing frictional capacity. The weighted average non-core reservation factor in southern California is 122 per cent, but again, to be conservative, PGT uses a factor of 11 per cent of non-core as part of the additional capacity reservation. As is evident from Table 3-23, southern California currently enjoys surplus capacity which will prevail until the late 1990s. The PGT Expansion Project into southern California (505 MMcf/d) will not be completely utilized until the year 2005.

In Altamont's view, PGT's argument that additional pipeline capacity is needed to accommodate peak requirement and to serve interruptible users is not persuasive. Capacity that is needed to serve peak core demand in December through February is available to serve non-core demand the rest of the year, including non-core peak demand in April, July and September. So, to inflate core demand by 41 per cent and non-core by 12.5 per cent is double counting. It is irrational to provide firm capacity for customers who have explicitly chosen cheaper interruptible service. However, PGT argues while there is no question that unused core capacity may be used to "firm-up" deliveries to interruptible shippers during certain months of the year, the fact is that many other non-core end-users will clearly desire firm interstate capacity on a year-round basis to meet their gas requirements.

3.3.3 Comments on the Proposed Capacity Requirements

Altamont and PGT are in agreement about current excess capacity available in the southern California market. Both analyses show that any incremental demand for capacity will not occur until sometime between 1995 and the year 2000. PGT's detailed analysis, in its submission, shows that not until 1997 does southern California start requiring additional capacity. Moreover, with PGT's proposed capacity in place, southern California would not experience capacity deficiency until beyond the year 2005. Similarly, Altamont's analysis indicates that the full expansion volume of approximately 500 MMcf/d will not be fully utilized until some time over the period 2000 to 2005.

It is, therefore, evident that any market captured by producers via either of the proposed projects into southern California is a displacement market over the next 5 to 7 years. That does not necessarily mean producers should back away from that market. But they should recognize the possibility that excess capacity will ultimately lead to price discounting and lower revenue.

The extent to which a producer can effectively compete in the marketplace depends to some degree on the nature of his end-use customer. Altamont's argument that its project provides direct interconnective possibilities, and thus by-passes the utilities at costs for transportation that are a fraction of those of the distribution system, should be assessed, particularly given the nature of the end-use market and its physical location with respect to the interstate pipeline. The potential for growth in industries where by-pass is a possibility, emphasizes the importance of competitive transportation rates.

Altamont and PGT differ in their views regarding capacity requirements for northern California. Altamont believes that no additional capacity is needed until some time over the period 2000 to 2005. PGT shows a deficit from the start of its forecast period to the year 2010. This deficit, in PGT's view, will prevail even with the addition of 250 MMcf/d of its proposed expansion to serve northern California.

Given PGT's projection of interstate shipments required into northern California, the current pipeline capacity of 2160 MMcf/d is not sufficient to meet average daily demand. With the proposed expansion of 250 MMcf/d into northern California, PG&E will face a constraint in meeting average daily requirement only by the year 2000. To the extent the PGT Expansion Project offers additional capacity to meet peak demand in northern California, this raises a question as to whether new pipeline capacity is the most efficient way to meet such demand. Alternate approaches include expanding storage facilities and relying more heavily on interruptible supplies. Neither of these options has been assessed during this proceeding.

3.4 STATUS OF CONTRACTUAL COMMITMENTS BETWEEN BUYERS AND SHIPPERS OF ALBERTA GAS

3.4.1 Altamont View of its Market Commitments

Deliveries of Alberta gas on Altamont are not scheduled to commence until late 1993, almost 1.5 years from now. In light of the timing and the continuously changing plans and initiatives of gas purchasers, marketers, and consumers, Altamont does not expect all of the contractual commitments between end-users and shippers to be completely finalized until sometime closer to the in-service date of the pipeline. A summary of the status of shippers' market commitments appears in Table 3-24, while Appendix C describes in detail each of the shippers contractual commitments, where available, from supply sources to end-use markets. The total shipper transportation commitment on Altamont is for 719 MMcf/d. Although Kern River's current application in front of the FERC is for a 452 MMcf/d expansion, Altamont points out that three[k] of its shippers currently hold capacity on the base Kern River system which could be used to transport Altamont volumes into California. Amoco Canada (Amoco), one of the largest shippers on Altamont and a shipper on the Kern River base system, states that the fact that it has demand charge commitments on Altamont and NOVA provides an incentive to maximize the flow of Alberta gas at as high a load factor as possible. The Rocky Mountain supplies currently flowing on the base Kern River system, would then be diverted to other markets.

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k Amoco Energy Trading Corporation currently holds 50 MMcf/d of capacity on the base Kern River system. Similarly, Chevron and Union Pacific Fuels each holds 100 MMcf/d.

Altamont noted that there will not be an incremental market for 719 MMcf/d when the pipeline starts to deliver gas in 1993. Although few end-use market contracts have been signed, Altamont has identified 426.4 MMcf/d[1] that will start to flow on a firm basis, displacing more expensive US supplies, and expects the remainder of the capacity to be used on an interruptible basis until shippers find firm markets for their gas.[25]

Altamont explains that the reluctance of producer shippers to sign up firm markets well before the pipeline's in-service date is a result of current low market prices and regulatory uncertainty. Altamont asserts that producers would prefer to wait in anticipation of higher market prices and the resolution of various regulatory uncertainties before they commit their volumes.

Table 3-24 Altamont Shippers and Volumes

Shipper's Name	Capacity Reserved	Buyers' Contractual Commitments (MMcf/d)		Market Area
		Finalized*	Under Negotiation	
Amoco Canada	102.5	25	77.5	California
Bow Valley Industries	50	0	0	Pursuing Markets
Chevron	40	0	40	California
ConWest Exploration	10	0	0	California-Nevada
Conoco	5	0	0	PNW-Rocky Mtns.
Entech	50	0	50	PNW-Rocky Mtns.
Inverness Resources	5	0	0	Pursuing Markets
Northridge	10.309	0	0	Pursuing Markets
Pacific Interstate Co.	200	0**	200	Southern California
Santa Fe Energy	20	20	0	Southern California
Tenngasco	94.991	0	94.991	California
Union Pacific Fuels	50	50	0	California-Midwest
Wes Cana Energy	31	0	0	Southern California-Nevada Utah-Northern Mexico
Western Gas Resources	50	0	0	Western US-Rocky Mtns.
TOTAL	718.8	95	472.491***	

* Contracts with end-use markets signed.

** Subject to CPUC approval.

*** The difference between total capacity reserved and volume of end-use market committed or still under negotiation represents the volume of gas for which shippers are either still pursuing markets or have not commented on their marketing efforts.

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1 The shippers and volumes identified by Altamont are: Amoco Canada at 25 MMcf/d; Chevron at 40 MMcf/d; Conoco at 5 MMcf/d; Entech, Inc. at 36.4 MMcf/d; Pacific Interstate Company at 200 MMcf/d; Santa Fe Energy at 20 MMcf/d; Union Pacific Fuels at 50 MMcf/d; Western Gas Resources at 50 MMcf/d.

3.4.2 Shippers' View of Altamont Market Commitments

Amoco, one of the largest shippers on Altamont, stresses the advantages of access to the developing pipeline hub at Opal, Wyoming. This access provides the opportunity to move gas through combinations of displacements, forward and backhauls. The pipeline hub at Opal provides a mechanism for Altamont to access nearly any market in North America if primary markets do not take previously contracted gas. In addition, Altamont cites the opportunity for customers to directly connect with the Kern River system at a tariff significantly less than the utilities' intrastate rate. This opportunity is not available on the PGT Project.

SDG&E, a shipper on the proposed PGT Expansion Project, points out the three largest southern California end-users have rejected the Altamont alternative. SoCal Edison and SDG&E are committed to the PGT Project, while the Los Angeles Department of Water and Power is meeting its requirements through the Kern River base system. Moreover, SDG&E submits that the absence of any commitment to Altamont from the three largest customers in southern California raises serious doubt about the viability of the project.

3.4.3 PGT View of Altamont Market Commitments

PGT notes that while Altamont contends that its primary market is southern California, two of the three largest customers in this region, namely SoCal Edison and SDG&E, will be served by the PGT Expansion Project. PGT also points out that Altamont's largest customer, Pacific Interstate Company (PIC), an affiliate of SoCalGas, still has not executed purchase contracts with Canadian producers or marketers, and that SoCalGas has no intention of entering into agreement with Altamont without the strongest regulatory support from the CPUC. In addition, given SoCalGas' existing reservation for core requirements on El Paso and Transwestern, PGT claims that SoCalGas has no room available to accommodate any Altamont supplies.

PGT comments on contradictory statements made by Altamont's supporters. Amoco says the pipeline will pass through a prolific Rocky Mountain Basin area, while Kern River on the other hand told the FERC that after 6 years of solicitation, it did not have interest from Rocky Mountain producers to support the expansion of Kern River domestic production. This, in PGT's view, leaves considerable uncertainty as to whether Rocky Mountain Supply will or will not compete for space on an expanded Kern River system.[26]

3.4.4 PGT View of Its Market Commitments

PGT has summarized its various classes of shippers in Table 3-25.[27]

Table 3-25 PGT Expansion Project Market Subscription

Use Category	Volume
End-Use in California	319.5
End-Use in Pacific Northwest	94.4
End-Use Domestic Canadian	5.0
Producer-Marketer-Aggregator	458.7
TOTAL AT KINGSGATE	877.6

End-use shippers account for 413.9 MMcf/d of the expansion volumes and of this total gas supply, contracts have been executed for 395.8 MMcf/d. Of the 458.7 MMcf/d of capacity held by producers, marketers and aggregators, approximately 91.3 MMcf/d has been contracted to an end-use market. Markets for the remaining 367.4 MMcf/d are in various stages of negotiation. A summary of the status of each shippers' commitment to market is contained in Table 3-26, while Appendix D describes in detail each of the shippers contractual commitment, where available, from supply sources to end-use markets. Some of this market information has been revised since the oral examination.

3.4.5 Altamont View of PGT Market Commitments

Altamont asserts that, notwithstanding the PGT sponsors' claim that their project is fully subscribed, the evidence is unrebutted that approximately 25 per cent of the capacity on the PG&E portion of the project has not been subscribed. In addition, many of the shippers who have executed contracts for capacity on the PG&E expansion insisted on renegotiation clauses, which could permit them to walk away from the project if the CPUC denies a partial roll-in rate for northern California. Altamont, therefore, concludes that PGT's market commitments are subject to some uncertainty.

Table 3-26 PGT Shippers and Volumes

Shipper's Name	Capacity Reserved	Buyers' Contractual Commitments (MMcf/d)		Market Area
		Finalized*	Under Negotiation	
BC Gas Inc.	5.0	0	0	Domestic Shipper
BP Resources	9.96	0	0	--
CanWest Gas Supply	75.95	0	75.95	California
Cascade Natural Gas	3.62	0	0	PNW
Chevron	19.44	0	19.44	PNW
Chevron	30.47	0	30.47	California
City of Burbank	4.82	4.64	0	City of Burbank
City of Glendale	3.97	3.92	0	City of Glendale
City of Pasadena	3.97	3.92	0	City of Pasadena
DeKalb Energy	11.43	0	11.43	Northern California
IGI Resources	6.96	6.96	0	PNW-California-Rocky-Mtns.
Norcen	47.02	0	0	California
North Cdn. Oils Ltd.	38.09	0	0	California
North Cdn. Marketing	19.04	0	0	California
Northern California Power	5.33	5.33	0	Northern California
Northridge Alberta Gas	7.84	0	0	--
Northwest Natural Gas	37.2	37.2	0	PNW
Pan Alberta Gas Ltd.	57.91	57.13	0	California
PanCanadian**	39.74	10	0	PNW-California
PanContinental Oil	3.92	0	3.92	--
Paramount Resources	19.02	0	19.02	Southern California
Petro-Canada	19.04	19.04	0	California
Sacramento Municipal	11.67	11.67	0	Northern California
Salmon Resources	27.70	0	27.70	California
San Diego Gas & Electric	51.04	51.04	0	Southern California
Suncor, Inc.	39.23	0	0	California
Southern California Edison	196.03	196.03	0	Southern California
Vector Energy	16.71	0	16.71	California
Wash. Energy Exploration	19.04	0	0	California
Wash. Energy Exploration	34.35	0	0	PNW
Wash. Water Power Co.	41.23	41.23	0	PNW
WP Natural Gas	3.22	0	3.22	PNW
TOTAL	904.96	448.55	207.87***	

* Contracts with end-use markets signed.

** PanCanadian's volume of sales increase from 10 MMcf/d in the first year of contract by 1 MMcf/d a year to a total of 19 MMcf/d by year 10 of the contract.

*** The difference between total capacity reserved and volume of end-use market committed or still under negotiation represents the volume of gas for which shippers are either still pursuing markets or have not commented on their marketing efforts.

3.4.6 Comments on Projects' Market Commitments

The PGT Expansion Project has more firmed-up market in terms of signed contracts for gas sales than the Altamont/Kern River Project. The reluctance of some shippers to commit to supplies and market has been exacerbated by lingering uncertainty regarding regulatory issues and the actual pipeline capacity that will ultimately be built. Given that PGT construction is already underway, it may not be surprising that there are greater volumes committed to it than to Altamont.

4.0 EX-ALBERTA PIPELINE FACILITIES

4.1 DESCRIPTION OF FACILITIES

Altamont

Altamont is a joint venture of three companies; Tenneco-Altamont, a subsidiary of Tenneco Gas Inc. holds a 53.3 per cent interest; Amoco-Altamont, a subsidiary of Amoco Production Company and an affiliate of Amoco Canada Petroleum Company Ltd. holds a 33.3 per cent interest; Entech-Altamont, a subsidiary of Entech Inc. (a subsidiary of Montana Power Company) holds a 13.3 per cent interest.

Altamont proposes to construct a 30-inch pipeline with a capacity to transport 719 million cubic feet of gas per day (MMcf/d) along an approximately 620-mile route extending from the Alberta-Montana border near the Port of Wild Horse, Montana to a connection with the Kern River pipeline near Opal, in southwestern Wyoming (see Map 1). With the exception of certain river crossings to be pre-built, the project will be constructed over a period of approximately six months immediately prior to the in-service date of 1 November 1993.

Kern River

Kern River is owned equally by Kern River Corporation, an affiliate of Tenneco Inc. and Williams Western Pipeline Company.

Kern River's base system, which commenced service in February 1992, originates at points of interconnection with the pipelines of Northwest, CIG and Questar near Opal, in southwestern Wyoming, and extends in a generally southwesterly direction through Utah and Nevada into southern California. At a point near Daggett, California, the base system converges with the pipeline system of Mojave. From Daggett to the termination points in Kern County near Bakersfield, California, Kern River and Mojave share the Common Facilities.

Between Opal and Daggett, Kern River's Mainline consists of 683 miles of 36-inch pipeline and three compressor stations having an aggregate compression power of approximately 26.6 MW. With these Mainline facilities, Kern River is capable of transporting 700 MMcf/d. In addition to the interconnections at its origin near Opal, Kern River's base system interconnects with the pipeline facilities of Southwest Gas Corporation (Southwest) in Nevada, and with PG&E and SoCalGas in California.

The majority of Kern River's base system throughput of 700 MMcf/d is sourced in the United States from large gas processing plants in southwest Wyoming and Kern River's interconnections with the interstate pipeline systems of Northwest, CIG, Questar, and Southwest. The balance of Kern River's base system throughput is sourced in Western Canada and delivered by Northwest to Kern River at their interconnection near Opal, Wyoming.

The Common Facilities are designed to have an initial capacity of approximately 1100 MMcf/d; Kern River will have the exclusive use of 700 MMcf/d and Mojave the remaining 400 MMcf/d.

The proposed Kern River Expansion will increase the capacity by 452 MMcf/d. This will be accomplished primarily by additional compression of 118.5 MW at seven new compressor stations and two existing stations. The Common Facilities are currently planned to be expanded by either

652 MMcf/d to accommodate the combined additional requirements of Kern River (452 MMcf/d) and Mojave (200 MMcf/d) or 452 MMcf/d to accommodate the requirement of Kern River only. The construction time required for the proposed expansion facilities is approximately 10 months and the schedule will be driven, in large measure, by Altamont's construction schedule.

Kern River's Expansion might reach a level of 550 to 560 MMcf/d due to the fact that Altamont recently negotiated transportation contracts for an additional 106.3 MMcf/d into California after its initial submission to this proceeding. Kern River's current position is to obtain a certificate for its original proposed expansion and then amend it later to account for any additional volumes contracted on Altamont rather than amending its application at the current time.[28]

ANG-Foothills

ANG, an affiliate of PGT, owns and operates the section of the Alberta - California pipeline system in BC from the Alberta-BC border to the Canada - USA border near Kingsgate, BC where it connects with PGT facilities. ANG's existing facilities consist of 106.1 miles of 36-inch main pipeline, four loops of 36-inch pipeline totalling 4.1 miles in length and three compressor stations with a total of seven units ranging in size from 7.5 MW to 11 MW.

Foothills was established to design, construct and operate the Canadian portion of the Alaska Natural Gas Transportation System. Foothills (South BC) owns 54.4 miles of 36-inch pipeline in four segments which parallel ANG's facilities. Foothills' system is connected with ANG and operated by ANG. The existing ANG-Foothills system has a capacity of 1 616 MMcf/d.

The ANG-Foothills Expansion project will generally follow the existing right-of-way and will be operationally integrated with the existing systems. The expansion facilities are designed to have a capacity of 930 MMcf/d at the Alberta-BC border and to transport an additional annual average volume of 877 MMcf/d of Canadian gas. The expansion facilities will consist of four additional segments of 42-inch pipeline totalling 48.2 miles and three additional compression units totalling 42 MW along with some modification work at existing stations. Construction of the compression facilities will begin in January 1993 and installation of the pipeline will take place in the summer of 1993 for commercial operation by November 1993.

PGT

PGT, a wholly-owned subsidiary of PG&E, was incorporated in 1957 as part of the Alberta - California project to serve as the interstate transporter of Canadian natural gas for PG&E. PGT's system is a 42-inch pipeline 612.5 miles long, with 201.5 MW of compression at 12 stations, passing through the states of Idaho, Washington and Oregon. PGT's pipeline connects with the facilities of ANG at Kingsgate, BC, with PG&E at the California-Oregon border near Malin, Oregon and with Northwest near Spokane, Washington and near Stanfield, Oregon. The existing PGT system has a capacity of 1020 MMcf/d.

The PGT Expansion Project is designed to provide additional firm transportation capacity to deliver 148 MMcf/d of Canadian gas to customers in the Pacific Northwest and 755 MMcf/d to California. The proposed expansion will effectively complete the looping of all unlooped portions of the existing PGT system with approximately 430 miles of 42-inch pipeline, one new compressor unit (22 MW), and two replacement units (22 MW to replace 7.5 MW) at existing stations. In addition, there will be various modifications at all existing stations to accommodate the higher flow rate. Construction of the

pipeline looping will occur from January 1992 through October 1993. Compressor station work is scheduled to commence in the late spring of 1992 and be completed in November 1993.

PGT estimates that with additional compression but no additional looping, the expansion system could be further expanded to deliver a maximum additional flow of 533 MMcf/d at an approximate present day cost of $300 million.[29]

PG&E

PG&E serves more than 11 million people in a 243 000 square km territory in northern and central California. PG&E's Mainline transmission system is connected with the facilities of PGT by its Line 400 at Malin, Oregon, with El Paso and Transwestern by its Line 300 near Topock, Arizona, and with Kern River in Kern County, California.

The PG&E expansion is designed to provide an additional firm transportation capacity of 755 MMcf/d of Canadian gas to customers in California with 250 MMcf/d to northern California and 505 MMcf/d to southern California. This 250/505 split was an illustrative calculation developed during the summer of 1991. PGT believes that it is possible more than 250 MMcf/d will ultimately end up in northern California. A higher disposition into that region would not significantly change the facilities from those currently proposed, since a significant portion of northern California incremental demand for gas is expected to be delivered south of Panoche Junction and the southern part of the Bay Area.[30] The expansion will involve looping PG&E's Line 400 with 42-inch pipe for 300 miles from the Oregon-California border near Malin to a new compressor station (10 MW) in the San Francisco Bay area. South of this station, looping will continue with 36-inch pipe for 115 miles to a terminus at the Panoche Metering Station in Fresno County. Five existing PG&E compressor stations will be modified and one new 10.5 MW compressor will be installed in an existing station to accommodate the additional gas flow. Piping modifications will also be made at PG&E's Kern River and Panoche Metering station. Construction will take place from December 1991 through October 1993. The first construction commenced in December 1991 at the Sacramento River Delta area with horizontal directional drilling for three water crossings and will continue until August 1992. Compressor station work is scheduled to have commenced in the late spring of 1992 and be completed in November 1992.

4.2 CONSTRUCTION SCHEDULES

4.2.1 PGT View of Altamont Construction Schedule and Altamont Response

It is the view of PGT that Altamont cannot meet its in-service date of 1 November 1993 for the following reasons:[31]

- Altamont has not ordered its compressors yet and given the long lead time in equipment ordering, suppliers could be hard pressed to meet the 1993 in-service date. It would also be difficult to change suppliers as compatibility problems could result.

- Altamont's river crossing work on the Missouri River needs to be started by August 1992 to meet the in-service date. Given the comprehensive nature of environmental work required, Altamont will not be able to complete the requisite environmental and cultural resource work in time to start these river crossings on schedule.

- Altamont has not chained and pinned its line and, as a result, does not have a good estimate of the length of the pipeline needed. Moreover, Altamont's estimate of metres of pipeline required keeps changing, indicating there is remaining on-the-ground survey work to be done.

- PGT does not see any work being done in the area of bidding with contractors.

Altamont's response to the PGT view of its construction schedule is as follows:[32]

- Solar, Altamont's compressor supplier, has informed Altamont that its 1993 in-service procurement schedule can be met. Altamont intends to begin ordering compressors in either May or June.

- A cultural resource survey of the entire right-of-way except for 19 miles to which Altamont could not obtain access, is completed. The mitigation of 27 potential sites of importance identified in the cultural resource survey is scheduled to begin the summer of 1992. Altamont is of the opinion that it does not need to begin its river crossings until 1 September 1992 to meet its in-service date.

- Altamont completed a horizontal survey and used aerial photographs to determine an accurate length of its pipeline. Altamont also states that normally there is no need for an actual chain survey until just before construction start-up.

- Altamont states in its Final Argument that it has placed orders for 628 miles of pipe.

4.2.2 Altamont View of PGT Construction Schedule and PGT Response

PGT stated, during the oral examination, that construction on various spreads of the proposed expansion has commenced.

Altamont raised the following issues regarding PGT's ability to meet its in-service date:

- Delays in construction experienced by PGT were due to the fact PG&E did not have its shipper contracts filed with the CPUC as required.[33] Altamont also cautions that delays will ultimately end up in higher project costs.

- Approval to begin construction on Spread 1 of the PGT Expansion Project on 1 January 1992 was refused by the office of Pipeline and Producer Regulations.[34]

PGT's response to these issues is as follows:

- Since capacity is firmly committed upstream of Malin, the necessity of California contracts does not affect the decision to proceed or not.[35]

- Because of uncertainty concerning some environmental issues, PGT states that it deliberately requested a Leave to Construct from the FERC in January, knowing that some additional studies would still be required. As a result, PGT is now specifically aware of what studies are still needed.[36]

- Construction schedules are very generalized and include such matters as gathering information and obtaining various clearances. So actual ground-breaking does not necessarily have to occur on dates given in a schedule. PGT states that any delays experienced are well within the contingencies it has available within the total project budget.[37]

- The fact that PGT signed contracts with some shippers specifying a November 1993 start-up date, and that some shippers made business arrangements accordingly, provides an incentive to bring the project in on schedule and within budget, at a time when shippers are quite sensitive to transportation tolls.[38]

4.2.3 Comments on Construction Schedules

The engineering and environmental work for Altamont is relatively less advanced than for PGT. In addition, Altamont has yet to place orders for compressors.[39] *However, that does not mean Altamont is less likely than PGT to meet its scheduled in-service date. Altamont's route is less complex; whether it is ahead or behind PGT is one more uncertainty.*

4.3 COST OF FACILITIES

4.3.1 Cost of Altamont/Kern River Expansion Project

The total ex-Alberta cost of Altamont's 719 MMcf/d capacity project is $1001.42 million (1991C$) according to Altamont's latest figures. The cost of the Canadian portion of the Altamont pipeline, consisting of a 300 metre pipeline at the Alberta-Montana border connecting NOVA's facilities to Altamont's, is estimated to be $336 214 (1991C$).[40] The US portion of the pipeline, consisting of approximately 1000 km of pipeline from Wildhorse, Montana, to Opal, Wyoming, will cost $676.915 million (1991C$).[41] The Kern River portion, which will consist of an expansion of Kern River's base system by 452 MMcf/d, is projected to cost $324.168 million (1991C$).[42]

4.3.2 Cost of PGT Expansion Project

The total ex-Alberta cost of the PGT Expansion Project is $1926.8 million (1991C$). The estimated costs of the ANG and Foothills portions of the Expansion Project are $86 million and $110 million (1991C$)[43], respectively. The PGT portion of the Expansion Project, consisting of looping all portions of PGT's existing system with approximately 692 km of pipeline, is expected to cost $868.2 million (1991C$).[44] The PG&E portion of the Expansion Project, which consists of looping PG&E's Line 400 to a terminus in Fresno County, is estimated to cost $862.6 million (1991C$)[45]. PGT has started construction and to date has spent approximately $400 million (US$).

4.3.3 PGT View of Altamont Costs

PGT argues that Altamont has significantly underestimated the costs of constructing its pipeline. The arguments presented by PGT are discussed below.[46]

Altamont estimates the cost of a single unit compressor station to be $12.6 million, while Kern River estimates the cost of a comparable unit to be $18.3 million. The actual cost difference between the two units should be, according to PGT, $0.5 million, leaving a difference of over $5 million unaccounted for. PGT believes that Altamont has underestimated the cost per unit.

Altamont's application with the FERC, filed 15 May 1990, indicates that the total capital cost of the proposed Altamont system to be \$573.483 million (1990\$). PGT claims that if Altamont had used the ERCB guidelines of 4.5 per cent inflation, and a 0.88 exchange rate, the cost in 1991 Canadian dollars should be \$681.011 million. PGT asserts that Altamont escalated its cost to 1993 US dollars using a 2.2 per cent inflation rate and then deflated back to 1991 dollars using a 4.5 per cent factor to give a total cost of \$636 million (1991C\$), which is 6.6 per cent lower than what it should be.

PGT also points to Kern River's "experience" in constructing its existing system. Kern River's capital costs have increased from its certified costs of \$761 million to \$917 million as of 9 August 1991, and PGT claims that company officials have stated that actual costs could reach \$985.4 million. PGT notes that the same has occurred with the cost of the Kern River expansion, whose cost estimate has increased from \$175 million in 1989 to at least \$308 million as of 19 November 1991[47].

Kern River states the cost overruns of its system claimed by PGT are invalid because they have not taken into consideration the vintage of the dollars used in Kern River's estimates, thereby falsely assuming that the differences in estimates are a result of cost overruns. Kern River also states that the comparison between Kern River's and Altamont's cost per mile of constructing the pipeline are too simplistic as they do not take into consideration such factors as topography, soil type, biological and cultural resources, and the degree of development along the right-of-way. It is also Kern River's opinion that the comparison of cost estimates for compressor stations are invalid since site-specific factors, such as right-of-way acquisition costs, terrain, elevation and environmental mitigation measures, vary between projects. It is, therefore, according to Kern River, not plausible to assume that Altamont's cost estimates should necessarily match those of Kern River.[48]

In December 1991, PGT commissioned Pipeline Construction Services, Inc. (PCS) to do an independent estimate of capital and construction costs of the Altamont project and compare this with Altamont's cost estimates as initially filed in this proceeding[49]. PCS's estimate of the full cost of the Altamont/Kern River Project is \$752 million (1993 US\$), approximately 21 per cent higher than Altamont's latest estimate.[m] PCS states Altamont has underestimated the following costs by the corresponding amounts:

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[m] Altamont has revised the estimate of costs in its 14 February 1992 submission. Facilities costs are now estimated to be \$620.320 million (1993 US\$).

Table 4-1 PCS Estimate of Altamont Project Cost Underestimation

Direct Plant Costs	Amount of Underestimation (1993 millions US $)
Total Mainline	79.04
Total Compression	39.77
Measurement Facilities	2.0
Engineering	10.57
TOTAL Direct Plant	129.39
Line Load	0.2
Allowance For Funds Used During Construction (AFUDC)	8.6
TOTAL COST UNDERESTIMATED	137.99

PCS derives its total cost using the following schedule:

Table 4-2 PCS Estimate of Altamont Project Cost

Description	(Millions) 1993 US$
Land & Land Rights	16.485
Pipeline	438.552
Compressor Stations	129.300
Metre Stations	1.539
SCADA Systems	6.475
Operational & Maintenance	3.700
Project Management & Engineering	38.700
Pre-Permit Costs	15.000
Insurance	22.670
Contingency	33.500
AFUDC	43.369
Line Pack	2.745
TOTAL COST	752.035

In arriving at its cost estimates, PCS used a pipeline length of 635 miles, rather than the 620 miles assumed by Altamont, to account for waste and an emergency stockpile.

Altamont, however, disputes PCS's claim that costs are underestimated.[50] PCS estimates the length of Altamont's project to be 622.283 miles with a total of 635 miles of linepipe needed to account for such things as horizontal deviations, slope distance, scaling errors, waste, and emergency stockpiles. Altamont has carefully studied pipeline alignment and is confident that pipeline length will be 618.3 miles, and that its cost estimates have already taken into consideration the additional pipeline that is necessary for variable factors (total pipeline length required is 620 miles).

Altamont views its estimate of the cost of acquiring land as more representative of actual costs. The average price of land in central Montana and Wyoming, where Altamont's project will be constructed, is between $200 - $450 per acre. Nearly one-third of the Altamont/Kern River Project will cross federal land, where a right-of-way grant can be obtained for $100 per mile. Altamont's per acre cost for land acquisition including damages, labour and overhead, is about $940, compared to PCS's estimate of $2000 per acre.

Altamont claims its linepipe costs are locked in pursuant to contract, therefore, PCS's claim of higher costs is irrelevant. It is Altamont's opinion that PCS overestimates pipeline installation costs by assuming a higher number of rivers, railroads, and canyons to cross. It also claims PCS is double counting in some instances. Altamont's estimate of the cost of metre stations, communications, and supervisory control and data acquisition already includes a contingency allowance, while PCS accounts for an additional contingency factor of 5 per cent.

During the oral examination, Altamont questioned PCS as to the validity of its estimates of Altamont's costs, which are 21 per cent or $131.7 million ($1993 US$) higher than Altamont's own estimates.[51] In its view, PCS has not done any routine reconnaissance with respect to Altamont's pipeline right-of-way, including looking at unique aspects of Altamont's construction. It is also Altamont's opinion that because PCS determined the pipeline's length from scaling using a route map, the estimate was higher. Altamont argues that the way in which land and right-of-way costs were determined was inaccurate. PCS used an average derived from looking at a number of similar projects from an article found in the 25 November 1991 issue of the Oil and Gas Journal. Altamont believes that this average is skewed as many of the average costs per mile of projects referred to in the article vary quite substantially. Altamont also finds fault in the fact that PCS did not consult with the Bureau of Land Management or companies experienced in construction of pipelines in this area of the US in delivering its estimate. Overall, though, the difference in costs for level and right-of-way between PCS and Altamont is quite small when compared with the overall costs of the Altamont/Kern River Project.

The major differences between Altamont's latest cost estimate and PCS's cost estimate can be accounted for by the following:

- PCS has included a 5 per cent contingency factor to the overall cost of the project which Altamont claims it has already included in its individual cost estimates. This difference accounts for $33.5 million (1993 US$).

- While Altamont allocated $16 million (1993 US$) for engineering, PCS identifies a total cost of $38.7 million for engineering and project management costs.

- As stated previously, there is a difference in estimates of linepipe needed. PCS's higher estimate of 635 miles accounts for an additional $16 million of costs.

- PCS's estimate for compressor station costs is almost $15 million higher.

- PCS calculated an allowance for funds used during construction (AFUDC) cost that was $6.5 million higher.

Together these five items account for over 15 of the 21 percentage points of difference between the two estimates.

4.3.4 **Altamont View of PGT Costs**

Altamont notes that PGT's costs have been changing in an upward direction, and points to the fact that the PGT Expansion Project's costs have climbed from $945 million (1993 US$) in 1988, to $1.7 billion (1993 US$) as of 30 December 1991.[52] It is Altamont's view that an extended two-year construction schedule increases the risk of escalating costs, particularly as it relates to the AFUDC. Altamont also points to the fact that October 1991 estimates of capital costs for the PG&E portion of the project were $736 million (US$). Current estimates are $800 million, an increase of 8.7 per cent in 3 months. Altamont is of the opinion that, overall, PGT has not offered assurances that the costs of its expansion project will not keep rising.

PGT responds to Altamont's criticism by stating that its project has undergone relatively little increase in its cost estimates. The initial estimate for the 755 MMcf/d design was $1.2 billion (1988US$). This has increased by only about 10 per cent over the last 3 years to $1.3 billion (1988US$). PGT claims that the escalations in cost were prompted by changes in the scope and complexity of the project, the environmental mitigation required, and the overall activity in the industry.[53] This risk is well within range of what other pipeline companies have experienced. PGT is confident that it can control costs effectively.

During the oral examination, PGT stated that any changes in scope of its project between now and completion will be borne by the owners.[54] These changes include putting in additional facilities over and above those defined within the agreement between the owners and project management group, Bechtel Corporation. However, any rerouting resulting because of right-of-way acquisition and/or post certificate permitting would be borne by Bechtel. Bechtel is also responsible for any changes in environmental mitigation costs.

Altamont also states that the fact that PGT has spent $400 million to date should not be considered as a prejudice by other parties against the willingness of Altamont to proceed with its project.[55]

4.3.5 Comments on Cost of Facilities

While Altamont's position that cost estimates for a project should be based on site-specific information appears reasonable, the fact that PGT has a fixed-cost contract with Bechtel, whereas Altamont has yet to do its final engineering has some significance.

4.4 COST ALLOCATION, RATE DESIGN AND ASSOCIATED RISKS

Both PGT and Altamont initially sought FERC approval for a certificate of public convenience and necessity through a traditional 7(c) application. However, Altamont's application was rejected by the FERC and it, subsequently, applied under an 'optional' or 'expedited' procedure to obtain a certificate. While Altamont is currently appealing the FERC's decision to deny its 7(c) application, it has accepted its optional certificate. As a result, the rates that PGT and Altamont filed were calculated using different rate design methodologies and the risks to producer netbacks associated with throughput shortfalls vary for each project. The different rate designs employed and their impacts on producer revenues are discussed below.

4.4.1 Altamont/Kern River Project

Under its 'optional' certificate Altamont did not have to file market data with the FERC. The pipeline sponsors are held at risk for throughput shortfalls as all fixed costs relating to return on equity and associated income taxes are recovered through the commodity component of the pipeline's rates. This method is known as a modified fixed variable rate design. In addition, Altamont is unable to apply to FERC for an increase in rates to compensate for actual throughput levels if they fall below the target throughput used in the pipeline's rate design.

In its first year of operation, Altamont anticipates total fixed costs to be $119 959 000 (nominal) Canadian dollars.[56] Of this total, $39 118 000 associated with return on equity and related taxes has been allocated to the commodity charge to be recovered from gas volumes that actually flow along the pipeline. The commodity charge is established at a 95 per cent pipeline load factor; if actual throughput volumes fall short of this level then Altamont will fail to generate sufficient revenue to cover its approved rate of return on equity. Shippers' average transportation costs would therefore rise, as their fixed demand charges are spread over smaller volumes. Because a significant portion of fixed costs is allocated to the commodity component of Altamont's rates, its demand charges are somewhat smaller than they would be under other rate design methodologies.

Like Altamont, the Kern River Expansion is subject to a modified fixed variable rate design despite the fact that Kern River has applied for its expansion under a traditional 7(c) application. Kern River explains that contractual obligations with shippers prohibit a change in its rate structure.[57] The expansion costs are to be rolled into the costs for the base system so that expansion shippers and existing shippers will pay the same rate, which is expected to be lower than the rate paid on the existing system.

4.4.2 PGT Expansion Project

Under its application for a traditional 7(c) certificate, PGT managed to satisfy the FERC that a market exists for the proposed pipeline's volumes. As a result, the FERC allowed all fixed costs included in its cost of service, including return on equity and related taxes, to be recovered through a demand charge. This is known as a straight fixed variable rate design and shippers bear the full cost of underutilization through higher unit transportation rates.

In its first full year of operation, PGT estimates its total cost of firm service for the expansion facilities to be $156 700 000 (nominal) Canadian dollars.[58] PGT is under no risk from pipeline underutilization as its return on equity is guaranteed by its firm shippers through the monthly demand charges that they are obligated to pay. As no component of fixed costs is recovered through the commodity component of the pipeline's tariff, lower load factors will cause unit transportation costs to rise more sharply than under the modified fixed variable rate design. PGT doubts that regulators would stand by and allow shippers to bear the full costs of underutilization if the pipeline continued to operate under very low load factors.

For the PG&E portion of the PGT Expansion Project, rates are regulated by the CPUC. These rates have been designed using the modified fixed variable methodology and the commodity component of the tariff has been based on a 95 per cent load factor. Therefore, if actual load factor falls below 95 per cent, the pipeline will bear some of the costs of underutilization and not fully recover its allowed return on equity. However, in subsequent rate hearings before the CPUC, PG&E can apply to have its

target throughput lowered for purposes of rate design. If this application is approved by the CPUC without a corresponding reduction in authorized return, a higher commodity rate would be charged.

Expansion shippers have also contracted with ANG for transportation service which will require an expansion to both the ANG and Foothills facilities. In May 1992, the NEB approved ANG's request that the cost of the expansion facilities be tolled on a rolled-in basis with existing facilities.

4.4.3 Risks to Altamont Rates

Table 4-3 summarizes the major assumptions used in the Altamont and Kern River Expansion rate designs. It should be noted that Altamont's annual depreciation cannot be expressed as a simple percentage rate, because part of the normal depreciation is deferred for the first 15 years in order to levelize nominal rates. Similarly, Kern River levelizes nominal rates for 13 years by deferring return on equity rather than depreciation.

Altamont considers its rates to have long-term stability particularly because it is a new project, and as such, its rates are less likely to vary as a result of regulatory decisions shifting costs from existing system shippers to new shippers. PGT, on the other hand, sees some regulatory uncertainty creating a risk of increases in the Altamont/Kern River tariff. As the latter project's rates have been designed with certain fixed costs allocated to their commodity component, if their certificates were modified

Table 4-3 Altamont Pipeline Rate Calculations, Key Assumptions

	Altamont	Kern River
Load Factor	95%	95%
Debt-Equity Ratio	75/25	70/30
Debt Interest	9.25	9.22
Return on Equity	14.25	14.0
Rate Method	Incremental	Rolled-in

so that the pipelines no longer bore the risks of underutilization, their rates could rise significantly as a result of lower than anticipated throughput. Altamont has indicated, however, that even if their 7(c) application is approved they would unlikely accept a straight fixed variable rate design with the lower approved rate of return on equity that typically accompanies it[59]. Altamont is sufficiently confident in the competitiveness of its project to risk underutilization in order to collect a higher return on equity.

PGT has pointed out that, while Altamont accepted the FERC's Certificate of Public Convenience and Necessity in August 1991, many issues in the certificate were held in abeyance pending the resolution of the FERC's Construction Rule, Order 555. This order proposes to eliminate the optional certificate procedure and create a new at-risk framework which calls for rate structures designed on the basis of a load factor of 90 per cent or less. As a result, the FERC could accept an earlier request by Altamont to use a target load factor of 90 per cent, which would have the effect of increasing the unit rates filed by Altamont in this proceeding in the order of 5.5 per cent, if the rate of return on equity remains unchanged.

To the extent that Altamont has underestimated their capital costs, this will require a rate adjustment if the pipeline applies to the FERC to have any cost over-runs included in its rate base. The Kern River Base system filed a request for a rehearing with the FERC in March 1992 as realized costs amounted to 947 million dollars, which was 96 million dollars more than filed earlier. The FERC granted a rate increase in recognition of the higher costs: the firm rate on Kern River was raised from 59 to approximately 65 cents per Mcf.[60]

4.4.4 Risks to PGT Rates

Table 4-4 summarizes some of the major assumptions behind the PGT Expansion Project's rate design. Unlike the Altamont tariff, rates are not levelized and are thus projected to decline in both real and nominal terms over time, as the rate base is depreciated.

Table 4-4 PGT Pipeline Rate Calculations, Key Assumptions

	PGT	PG&E
Load Factor		
Demand	100%	100%
Commodity	N/A	95%
Depreciation Rate	3.33%	3.33%
Debt Equity Ratio	70/30-55/45	70/30-55/45
Debt Interest	9.3%	9.0%
Return on Equity	12.5	12.65
Rate Method	Incremental	Incremental

While a 7(c) certificate implies rate rehearings at least every 3 years, PGT argues that throughput shortfalls will not result in increases in future rates. This is because the rates are designed on a straight fixed variable methodology, the expansion is fully subscribed and, under existing guidelines, all the costs of the expansion will be recovered by existing demand charges regardless of throughput. However, Altamont has identified a number of risks related to PGT's rates that it claims will result in significant rate increases over time.

Altamont contends that incremental allocated rates, whereby new shippers are required to pay rates to reflect both the costs of the new facilities and a share of the cost of the existing facilities they would use, are advocated by both the CPUC and FERC for interstate pipeline expansion projects. For example, both regulatory bodies advocated an incremental allocated rate design for transportation services to Pacific Interstate Transmission Company (PITCO) on the PGT pipeline system. In addition, Altamont claims that in FERC's rate treatment for the US Northeast Expansion Projects to deliver Canadian gas into these markets, shippers were required to pay rates that reflected a pro-rata share of operating and maintenance (O&M) plus administrative and general (A&G) costs. The effect of incremental allocated rates, if adopted on the PGT Expansion Project, could be to reduce rates paid by shippers on the existing system while increasing rates faced by expansion shippers. This issue and others raised by Altamont are considered in more detail below and are summarized in Section 4.5.2.4.

Altamont argues that some existing facility costs on PGT (namely the PITCO loop, dual security river crossings and some existing compression) should be allocated to expansion shippers because these are the shippers who will benefit from these facilities. PGT responds that the FERC has approved initial

rates for the PGT Expansion Project based exclusively on incremental costs and in doing so, flatly rejected Altamont's proposals to shift costs from the existing system to the expansion project. PGT does acknowledge that the cost allocation between existing customers and expansion customers will be addressed in the context of a general rate case, after the new facilities are placed in service. However, PGT considers the likelihood of the CPUC or FERC allocating additional costs to the expansion system as extremely remote.[61]

Altamont notes that existing PG&E facilities used by the expansion have been assigned to the project's rate base using net book value. As these existing facilities have been heavily depreciated, the resulting rate impact is minor. Altamont argues that in future rate hearings more existing facilities costs on both the PGT and PG&E sections may be assigned to expansion shippers and that the average of the depreciated book value and replacement costs should be used in calculating costs to be assigned to the rate base. PGT states that Altamont is erroneous in suggesting that cost allocation of existing facilities will be based on some function of "replacement costs", as the FERC and its predecessor, the Federal Power Commission, have always approved gas pipeline rates based exclusively on embedded historical costs. PGT also added that it would be highly unlikely that the CPUC would undertake measures to make the existing service cheaper and thus increase existing netbacks at a time when it believes that the netbacks on the existing system are already "far higher than the market would independently determine".

Altamont indicates that O&M and A&G costs included in the PGT Expansion cost of service are only 3.1 per cent of O&M and A&G costs of its existing system. A pro-rata reallocation of these costs between existing and expansion shippers would result in significantly higher rates for the PGT and PG&E Expansions. PGT responds that in its suggestion about the allocation of O&M and A&G costs, Altamont wants it both ways. On the one hand, Altamont proposes a "super incremental" case in allocating capital costs from the existing system to the expansion while Altamont's call for a pro-rata allocation of O&M and A&G costs, is the equivalent of a full roll-in.

In its initial submission, Altamont claims that PGT used interruptible volumes as well as firm volumes in calculating its firm rates thereby lowering these rates by assuming a throughput in the order of 108 per cent. PGT dismisses the notion that interruptible volumes, which would be available from the increased power output of gas turbine compressor stations in the cold winter months, have been used to artificially lower firm rates. The expansion allocated a portion of costs to interruptible deliveries so the project sponsors are entirely at risk financially if these volumes do not materialize. Altamont, however, considers PGT sponsors to be at risk for shortfalls in interruptible volumes only until the next rate case when revenues forecast to be recovered from interruptible volumes that did not materialize, would be reallocated for recovery from other volumes. PGT views this issue as a symmetric risk, for if interruptible volumes were greater than anticipated, shippers would seek to have their rates lowered accordingly.

Altamont is also concerned that under a system of capacity brokering, any excess firm entitlement held by shippers would be brokered on an interruptible basis. If demand for interruptible service is fully satisfied by this brokered capacity there would be no interruptible revenues accruing to the pipeline. PGT contends that the demand for Canadian gas will be sufficiently robust so that not only would all the shippers' firm entitlements be used but the capacity in excess of these entitlements, that is available on an interruptible basis, will also be fully taken up.[62]

Under the present crossover ban imposed by the CPUC, expansion shippers to northern California must pay the equivalent of transporting their gas to the Kern River station in southern California plus

the full postage-stamp rate to take the gas to northern California markets. Altamont considers that this arrangement which is now under review by the CPUC, may be resolved by multiple delivery points being established on the expanded system for northern California shippers and, possibly, a system of mileage-based rates imposed. Altamont expects that such an outcome would significantly increase the PG&E rate for firm transportation to southern California. PGT responds that the CPUC is unlikely to approve mileage-based rates and that all gas transportation rates in California have been postage-stamp since the 1970's. In addition, as the California intrastate infrastructure is a network system that relies very heavily on displacement to provide service, PGT believes it would be very difficult to implement mileage-based rates.

Altamont also considers the possibility that expansion shippers' rates might be increased if PGT proposed a take-or-pay surcharge to recover the cost of any buy-out contracts with existing Alberta and Southern (A&S) producers. According to PGT, it does not envision a scenario in which the cost of reformation of any existing business would be borne by expansion shippers.

Finally, Altamont warns that the NEB may prevent the costs for the ANG expansion from being rolled-in with the existing system, which would serve to increase rates charged to existing shippers. This warning has been proven unfounded, however, as the NEB's GHW-2-91 "Reasons for Decision" approved the use of rolled-in tolls.

4.5 AVERAGE TRANSPORTATION RATES FORECAST BY REGION SERVED

4.5.1 Altamont/Kern River Project

4.5.1.1 Northern California

Altamont did not provide projections to serve northern California as the project has not been specifically designed to serve this region. To the extent that these volumes could reach northern California through an expansion to PG&E's Line 300, shippers would incur the costs outlined in Table 4-5 plus an additional PG&E rate.

4.5.1.2 Southern California

Based on the latest cost of service estimates available and the rate design methodology outlined earlier, the Altamont/Kern River Project's ex-Alberta pipeline costs are shown in Table 4-5.[63]

Table 4-5 Altamont/Kern River Project - Ex-Alberta Transportation Rates at 100 per cent Load Factor[n] (1991 Cdn ¢/GJ)

	1994	1995	2000	2005	2010
Altamont[o]	39.97	38.25	30.69	24.63	12.05
Kern[p]	49.42	47.29	37.95	30.45	12.62
TOTAL	89.39	85.54	68.64	55.08	24.67

Shippers wishing to transport their gas to southern California would incur costs on both the Altamont and Kern River pipelines and pay a total rate of 89.39¢/GJ (1991 C$). As mentioned earlier, rates on both the Altamont and Kern River systems have been levelized in nominal terms so that the rate to California would remain constant for 13 years and, thereafter, declines.

4.5.1.3 **Alternate Markets**

Altamont could serve up to 200 MMcf/d of gas to markets along the Altamont/Kern River route in the states of Montana, Wyoming, Colorado, Utah and Nevada. As both pipelines charge postage-stamp rates, firm shippers will have to pay the full rates charged by each pipeline even if their gas only travels a portion of the pipeline's length. These rates are summarized in Table 4-6.[64]

n While the demand and commodity rates were designed using a load factor of 95 per cent, these are the unit rates that shippers will pay if the pipeline operates at full capacity.

o Held constant in nominal dollars for 15 years then declining at an average 10.6 per cent per annum.

p Held constant in nominal dollars for 13 years then declining at an average 11.0 per cent per annum.

Table 4-6 **Ex-Alberta Rates to Non-California Markets (1993 ¢US)**

Market Served	System	Interruptible ¢/Mcf	Firm ¢/Mcf
Montana-Wyoming-Utah	Altamont	11	43
	TOTAL	**11**	**43**
Nevada	Altamont	11	43
	Kern River	14	53
	TOTAL	**25**	**96**
Colorado	Altamont	11	43
	Colorado Interstate	25	25
	TOTAL	**36**	**68**
Chicago	Altamont	11	N/A
	KN Energy	10	N/A
	Trailblazer	30	N/A
	NGPL	31	N/A
	TOTAL	**82**	**N/A**
Gulf Coast/Northeast US	Altamont/Kern	25	N/A
	Valero	10	N/A
	N.E. Pipeline	60	N/A
	TOTAL	**95**	**N/A**

In addition to the alternate markets that lie along the pipeline's route, Altamont expects markets to the east could be reached through various pipeline interconnections stemming from the developing hub of Opal, Wyoming, particularly on an interruptible basis. For example, an Altamont shipper could move gas on an interruptible basis to Chicago in winter, by delivering gas to KN Energy in Wyoming. In exchange, the Altamont shipper would be given volumes on the Trailblazer and Natural Gas Pipeline Systems which could be moved to Chicago for $0.82(US). As Altamont sees this market as a safety valve in the event of demand fluctuations in the southern California market, the Altamont demand charge has been viewed as a sunk cost and has, therefore, been excluded from this rate calculation.

4.5.1.4 Comments on Altamont Suggested Rates to Alternate Markets

Apart from PGT's criticism that Altamont's suggested rates to southern California are too low because they have been based on inappropriately low estimates of capital costs, it is doubtful that Altamont provides a viable option to serve eastern markets. Northern Border Pipeline Company (Northern Border) submitted evidence to show that even if Altamont's demand charges are ignored for serving the Chicago market, the Northern Border firm rate to Natural Gas Pipeline is still 8 cents/Mcf cheaper. While the interruptible rates on Altamont, KN Energy, and Trailblazer total 51 cents/Mcf(US), firm rates on Foothills and Northern Border are 11 cents/Mcf (US) and 32 cents/Mcf (US), respectively, for a total of 43 cents/Mcf (US).

4.5.2 PGT Expansion Project

4.5.2.1 Northern California

PGT submitted two sets of rates for the interstate portion of its project, one an incremental rate design and the other based on rolling-in the cost of the expansion with the existing facilities. In both scenarios, rates are mileage-based. The effect of rolled-in rates is to reduce rates for expansion shippers in the first year in the order of 38 per cent. The gap narrows thereafter with rates becoming equal in the year 2007 and a marginal rate advantage accruing to the incremental rate design for the remainder of the period. As the FERC has granted PGT a 7(c) certificate based on incremental rate design, the following rate discussion focusses on this particular method.

When PG&E filed its proposal for expansion with the CPUC, the commission did not want any of the expansion costs to be borne by existing shippers and as a result indicated that expansion costs should be treated on an incremental basis for rate design. At the urging of PG&E, the CPUC also imposed a crossover ban in June 1991, whereby expansion shippers on the PGT system would not be allowed to use the heavily-depreciated existing PG&E system to take volumes away at Malin. Thus, PG&E would be assured of being able to recover its revenues from shippers on the California portion of its expansion facilities. Under this proposal, expansion shippers to northern California would pay a rate equivalent to transporting the gas to the Kern River Station plus the existing postage-stamp rate to haul the gas back out of the mainline and to the burner tip. As this method involves double charging for some of the Mainline transmission functions, PG&E envisages paying a credit in the order of 11 cents per Mcf to reimburse shippers.[65]

The FERC has disapproved of the above arrangement and has viewed it as discriminatory and an illegal tie-in, since any shipper could obtain access to the existing PG&E system under the CPUC's proposed capacity brokering rules, as long as they are not shippers on the expansion project. While the FERC initially imposed a construction ban until the crossover ban is lifted, PGT was subsequently given permission to commence construction although the rate of return on equity it is able to collect on the expanded system was lowered to 10.13 per cent while the crossover ban remains. As a result, PGT has proposed a roll-in rate design to northern California whereby the costs of the expansion to serve northern California shippers are rolled-in with the costs of the existing PG&E facilities. This latter proposal is currently under review at the CPUC and their decision will be reviewed by FERC to consider whether to reinstate a return on equity of 12.5 per cent. The rates in both cases for shippers on the expansion serving northern California are summarized in Table 4-7.[66]

Table 4-7 Ex-Alberta Transportation Rates for Expansion Shippers to Northern California at 100 per cent Load Factor (1991 Cdn ¢/GJ)

	1994	1995	2000	2005	2010
Roll-in Rate Design for PG&E					
ANG-Foothills	6.7	6.4	5.2	4.5	3.7
PGT(Kingsgate to Malin)*	42.4	39.7	27.5	17.8	10.8
PG&E (Malin to Northern California)	16.5	16.2	14.4	12.6	10.7
TOTAL	65.6	62.3	47.1	34.9	25.2
Incremental Rate Design for PG&E					
ANG-Foothills	6.7	6.4	5.2	4.5	3.7
PGT-(Kingsgate to Malin)*	42.4	39.7	27.5	17.8	10.8
PG&E (Malin to Kern River Station)	43.4	39.7	28.6	19.1	11.8
Less: Credit for Backbone Intrastate Transmission	(10.8)	(11.0)	(11.2)	(10.9)	(9.8)
TOTAL	81.7	74.8	50.1	30.5	16.5

* Based on incremental cost allocation.

4.5.2.2 Southern California

While PGT submitted incremental and rolled-in rates for the Kingsgate to Malin portion of its project, for reasons mentioned earlier this discussion focusses on the incremental rate design. Shippers to southern California intending to use the expansion facilities will be faced with paying a postage-stamp rate on ANG, mileage-based rates on PGT, and a postage-stamp rate on PG&E. Regardless of whether PG&E's rate for northern California deliveries is rolled-in or incremental, southern California rates will be based on incremental costs. Table 4-8 summarizes the transportation rates incurred by shippers to southern California.

Table 4-8 Ex-Alberta Transportation Rates for Expansion Shippers to Southern California at 100 per cent Load Factor (1991 Canadian ¢/GJ)

	1994	1995	2000	2005	2010
ANG-Foothills	6.7	6.4	5.2	4.5	3.7
PGT (Kingsgate to Malin)*	42.4	39.7	27.5	17.8	10.8
PG&E (Malin to Kern River Station)	43.4	39.7	28.6	19.1	11.8
TOTAL	92.5	85.8	61.3	41.4	26.3

* Based on incremental cost allocation.

The rates filed in the Call for Information are based on a 12.5 per cent return on equity, rather than the rate of return of 10.13 per cent imposed by FERC until the crossover ban at Malin has been lifted. Based on this revision, PGT's rates would be somewhat lower than filed. As shown in the PGT filing to FERC, the following rates would apply under the various circumstances.[67]

12.50% ROR: 49.96¢/GJ (C$-nominal)
10.13% ROR: 46.75¢/GJ (C$-nominal)

These rates are somewhat different than filed in this proceeding because the Board specified certain other parameters.

4.5.2.3 **Pacific Northwest**

Shippers wanting to serve the Pacific Northwest via the expansion project, will face a variety of transportation rates since PGT is a mileage-based pipeline. The cost to shippers varies, depending on how far along the pipeline they wish their gas to travel. Incremental rates on PGT range from 2.0¢/GJ (1991 C$) for firm services from Kingsgate to Bonner's Ferry at 100 per cent load factor, to 41.4¢/GJ (1991 C$) from Kingsgate to Klamath Falls. These rates decline over time as the rate base is depreciated.[68]

4.5.2.4 ***Comments on PGT Suggested Rates***

While Section 4.4.4 of this report outlined in some detail the risks Altamont identified with respect to increases in PGT's rates, Table 4-9 summarizes Altamont's arguments and quantifies their impacts on the PGT's rates as calculated by Altamont.[69]

Table 4-9 Anticipated ANG-PGT-PG&E Rate Increases for Expansion Shippers (1993$)

	Anticipated Rate Increase	
	US $ per Mcf	**Cdn. $ per GJ**
PGT		
• elimination of interruptible volumes	.0196	.0211
• allocation of existing O&M and A&G costs on a pro-rata basis	.0400	.0431
• allocation of existing facilities costs at book value	.0219	.0236
PG&E		
• elimination of interruptible volumes	.0365	.0393
• allocation of existing O&M and A&G costs on a pro-rata basis	.0464	.0500
• allocation of existing facilities costs at book value	.0023	.0025
• adoption of mileage-based rates	.1222	.1316
TOTAL	.2889	.3112

While the above risks to PGT rates were identified and quantified by Altamont, the latter also added that it would be unlikely that each and every one of these adjustments is going to occur. Altamont believes there is a strong likelihood that some combination of these will actually take place, while the probability that none of the identified adjustments will occur is similarly very unlikely. It is possible that if interruptible volumes do not materialize, future rate cases might well result in higher rates for firm shippers. The other events, however, are hard to predict, as they would require specific policy decisions by various regulatory bodies.

Altamont also questioned the reduction in the rates charged to the PGT Expansion Project volumes over time as presented by PGT in the Call for Information. The rates on PGT and PG&E are forecast to decline annually as the rate base is depreciated. The mechanism through which this would occur on intrastate rates was identified by PGT to be an attrition mechanism that adjusts each utility's rates on an annual basis.[70] On the interstate system, a merchant pipeline like PGT would be obligated to file rate cases every 3 years with the FERC, and parties may require a filing more frequently. Although PGT did not know the exact pattern of how these rates would decline, it simplified the presentation by assuming that rates do decline annually.

This simplification of PGT's anticipated rate adjustments over time confers an unwarranted advantage to the expansion project when a comparison is made with Altamont rates over the life of the two projects. Current regulations in the United States make it highly unlikely that PGT rates would decline every year on an automatic basis as the rate base is depreciated. The uncertainty surrounding PGT's continuing status as a merchant pipeline creates doubt as to whether it will be obliged to file a rate case at a minimum of every 3 years. In addition, applications under Section 5 of the Natural Gas Act under which customers or the CPUC may initiate proceedings to challenge a pipeline's current rate, typically take longer than 1 year to conclude. As the FERC is then authorized to modify the existing rate on a prospective basis only, the occurence of annual rate adjustments appear highly unlikely.

4.5.3 ***Comments on Ex-Alberta Rate Comparison and the Impact of Variations in Load Factor***

The as-filed, ex-Alberta, unit transportation rates, for both projects operating at a 100 per cent load factor, are shown in Figure 4-1. While Altamont initially offers a tariff to Kern River Station that is lower by about 3.2¢/GJ (1991 C$), the PGT Expansion Project becomes the lower cost route in 1996 and remains so until the year 2009. Thereafter, Altamont's rates are slightly lower.

As the rate advantage shifts between the two projects over time, the time value of money must be incorporated in any comparison. The present value of a pipeline's per unit revenue requirement for

each year of operation can be determined, and a levelized tariff that could be charged each year to satisfy this requirement, can then be calculated.[q]

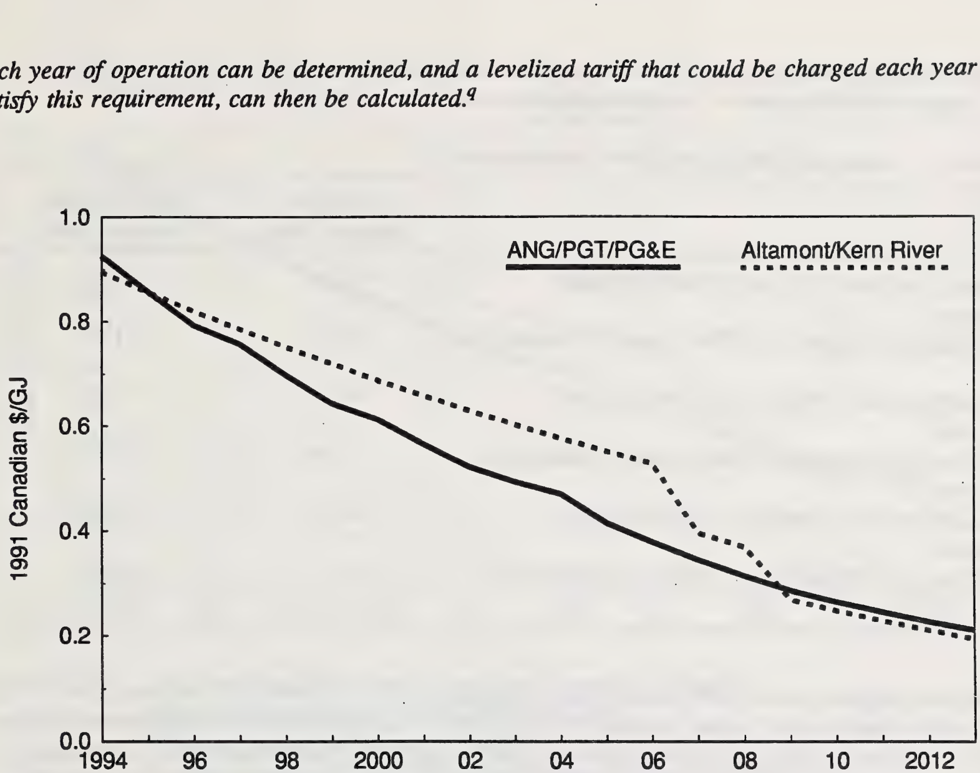

Figure 4-1 Unit Pipeline Tariffs at 100 Per Cent Capacity Utilization
Altamont/Kern River vs ANG/PGT/PG&E
Alberta Border to Southern California
Incremental rates on PGT and PG&E, rolled-in rates on ANG and Kern River.

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q $$PVT = \sum_{t=1}^{20} T_t (1 + r)^{-t}$$

where: t = time period
r = discount rate
T_t = unit rate in time period t
PVT = present value of total unit rates

Once this present value has been determined, then a levelized tariff that could be charged each year to satisfy the pipeline's revenue requirement can be calculated.

$$PVT = \overline{T} \sum_{t=1}^{20} (1 + r)^{-t}$$

$$\overline{T} = PVT / \sum_{t=1}^{20} (1 + r)^{-t}$$

where: $\overline{T}$ = Levelized unit rate

Table 4-10 shows the levelized rates for both projects at various discount rates. At a 5 per cent discount rate, the PGT Expansion Project holds a rate advantage in the order of 8.5 per cent.

Table 4-10 Levelized Unit Rates (1991 Canadian ¢/GJ)

	5 Per cent Discount Rate	10 Per cent Discount Rate
Altamont/Kern River Project (@ 100% Capacity Utilization)	60.90	66.14
PGT Expansion Project (@ 100% Capacity Utilization)	56.14	61.62
Altamont/Kern River Project (@ 75% Capacity Utilization)	74.90	81.28
PGT Expansion Project (@ 75% Capacity Utilization)	71.48	78.47
Altamont/Kern River Project (@ 50% Capacity Utilization)	102.92	111.57
PGT Expansion Project (@ 50% Capacity Utilization)	102.17	112.17

An implicit assumption in the PGT rates as filed is that the rates on the interstate portion of the project will decline annually in line with depreciation. As it is unlikely that PGT's rates would decline annually, the above analysis has been repeated assuming that PGT's rate would decline in nominal terms only every third year. With this adjustment to PGT's rates, the levelized unit rate at a 5 per cent discount rate increases from 56.14¢/GJ (1991 C$) to $56.5¢/GJ. Therefore, even under this assumption, PGT's levelized rates are slightly lower.

In addition to comparing the rates as filed, an analysis was conducted assuming capacity utilizations on both projects of 75 and 50 per cent. The result of this analysis is shown in Figures 4-2 and 4-3. As the PGT rates are more heavily weighted toward the demand component, by PGT's straight fixed variable rate design, the effect of a lower load factor is to increase Altamont's initial rate advantage and reduce the PGT advantage in later years. However, a comparison of both pipelines' levelized rates still shows PGT to be the more competitive project at 75% capacity utilization. Using a 5 per cent discount rate, Table 4-10 shows PGT's levelized rate to be around 5 per cent lower than the Altamont/Kern River rate. When utilization levels fall as low as 50 per cent, the levelized rates for both projects are virtually the same. To the extent that increases to PGT's rates are valid, as suggested by Altamont and outlined in Section 4.4.4, then the rate advantage of the PGT Expansion Project will be further eroded or even eliminated. Similarily, increases to Altamont's rates would increase PGT's advantage.

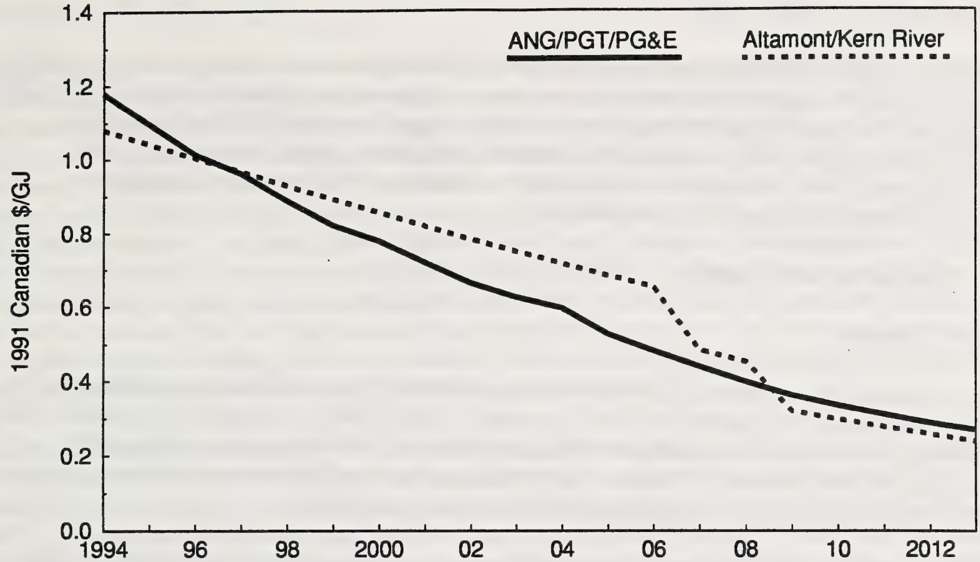

Figure 4-2 **Unit Pipeline Tariffs at 75 Per Cent Capacity Utilization**
Altamont/Kern River vs ANG/PGT/PG&E
Alberta Border to Southern California
Incremental rates on PGT and PG&E, rolled-in rates on ANG and Kern River.

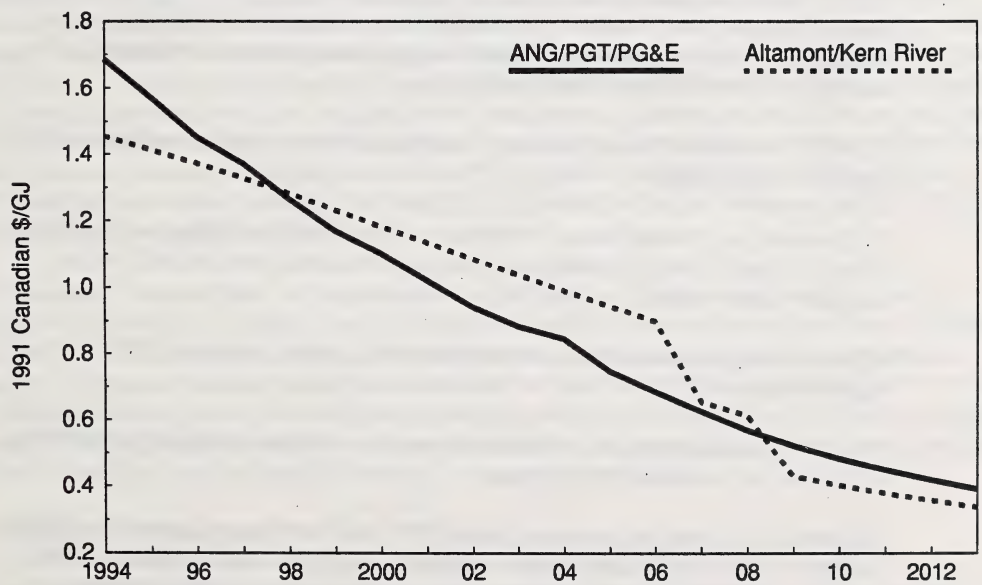

Figure 4-3 **Unit Pipeline Tariffs at 50 Per Cent Capacity Utilization**
Altamont/Kern River vs ANG/PGT/PG&E
Alberta Border to Southern California
Incremental rates on PGT and PG&E, rolled-in rates on ANG and Kern River.

4.6 PRODUCER NETBACKS

The potential impact of either proposed pipeline on the Canadian petroleum industry and, in particular, gas sales revenue, is assessed by the respective proponents. Altamont commissioned Brent Friedenberg and Associates (Friedenberg) and PGT employed Wright Mansell Research (WMR) to study the comparative netback gas price as a result of the addition of pipeline capacity into the California market. The purpose of this section is to outline both Altamont and PGT views and conclusions, followed by the Board's comments on the analyses.

4.6.1 Altamont Netback Analysis

Summary of Results

Altamont concludes that its project will add $10.0 billion (1991 C$) to the Alberta gas industry's plant gate sales revenues over the period 1993-2013, compared to $6.3 billion that would be generated if the PGT expansion is built instead. In Altamont's opinion, under the PGT alternative, existing A&S producers stand to lose the most; $3.3 billion (1991 C$) over the first 20-year period. Development of the Altamont project will not have any impact on these same producers.

In present value terms, and assuming a 10 percent discount rate, Altamont will generate $2.0 billion (1991 C$) more revenue for Alberta producers than the PGT Expansion Project. It concluded that on a per unit basis, producer netbacks via Altamont will be $1.55/GJ (1991 C$), compared to $0.65/GJ for PGT.[71] These results assume only one project is built and are based on the following:

1. Kern River's expansion of 500 MMcf/d will proceed regardless of whether incremental pipeline capacity from Alberta to California occurs. Altamont believes that such an expansion is likely because Rocky Mountain gas is competitive in California, in the absence of Alberta volumes through Altamont.

2. The PGT Expansion Project will cause a shift in California supply to a lower cost marginal supply basin.

3. If Altamont is to proceed alone, its volume will essentially be a substitute for Kern River's expansion and, therefore, would not have the same effect as PGT on the marginal supply basin.

4. Altamont compares the revenue requirements of its project to those of PGT on an equal-volume basis.

5. The PGT Expansion Project will erode netbacks to A&S producers serving northern California on the existing PGT system.

6. Altamont, in its analysis, calculates higher PGT tolls than those submitted by PGT to the FERC and to this Board. Such adjustments are outlined and explained earlier in Section 4.5.2.4. The only toll adjustments not included in the netback analysis are those where the net effect of incremental cost allocations between PGT's existing and expansion shippers is zero.

Description of Methodology

Altamont's study is based on a model that forecasts the flows of gas from producing to consuming regions. Gas prices vary among consuming areas and producing basins because of transportation costs. The model assumes that the Gulf Coast supply basin, because of its dominant size, indirectly drives the prices in other supply basins and, therefore, in the consuming regions. The supply basins include the Permian-Anadarko, San Juan, Rocky Mountain, British Columbia and Alberta. The consuming regions include California, the Pacific Northwest and the US Midwest. The Midwest is assumed to absorb those volumes of Alberta, British Columbia and Rocky Mountain gas which cannot fetch a comparable netback in closer consuming areas. Thus, the Midwest market is assumed to be the marginal market in which prices are established. Similarly, the Gulf Coast market is the marginal market for gas sales from the San Juan and Permian basins. The price of gas delivered from the Gulf Coast determines the market price in the Midwest. The opportunity price of gas from any of the producing basins is the netback from a sale to the marginal market.[72]

California prices are determined by the gas from the highest cost supply basin because it represents the source of the last Mcf sold in California. This gas, at present, is from the Permian Basin, whose plantgate prices are those obtainable by serving the best alternative market, the Gulf Coast. Thus, the Gulf Coast citygate price minus transportation costs to the Permian Basin plus transportation costs to California establishes the California citygate price. Altamont assumes a Gulf Coast price of $2.20/Mcf (US) in 1993 rising thereafter at the assumed inflation rate of 4.5 per cent per annum.[73]

The model utilizes Altamont's California gas demand forecast, discussed in Chapter 3 of this report. It then allocates supply to meet demand from the lowest to the highest opportunity price basin until demand in each year is satisfied. Interstate pipelines connecting supplies from the intra-marginal sources into California will be utilized at a 95 per cent load factor, whereas pipelines serving alternate markets such as the Pacific Northwest and the Rocky Mountain region will be utilized at a 75 percent load factor. The study further assumes that Altamont will deliver 620 MMcf/d of gas to California, 120 MMcf/d of which will flow on Kern River's base system. Altamont assumes that an additional 80 MMcf/d will be delivered to pipeline systems connected to Altamont in the vicinity of the Opal hub. As to the volume serving markets via the PGT Expansion Project, Altamont's assumption is that 755 MMcf/d is to serve California, 148 MMcf/d is to serve the Pacific Northwest, and BC sales into California are set at 60 MMcf/d.

The producer's netback price is then calculated as the market price less transportation cost. It is possible that the netback could exceed the opportunity price of gas in the producing basin. Having determined the volume of gas that could flow from the Alberta basin to the different consuming regions, a levelized netback price is then calculated for each project and is compared to the levelized Alberta opportunity price. This levelized opportunity price is the present value of Alberta plantgate revenue divided by the present value of gas volumes net of transportation costs to Alberta producers, from the next best market, the US Midwest.

Analysis Of The Results

Altamont examines four cases using the modelling methodology outlined above. The cases are:

1. Neither project proceeds.

2. PGT proceeds.

3. Altamont proceeds.

4. Both projects proceed.

In all cases Altamont considers that the Kern River expansion will materialize, with its costs to be recovered from US Rocky Mountain gas producers in Cases 1 and 2 and Alberta producers in Cases 3 and 4.

If neither project proceeds, the levelized netback of any incremental sales by Alberta producers would equal the Alberta opportunity price which, over the forecast period, will average $1.25/GJ (1991 C$) because it is assumed this gas would be sold in the Midwest market.

The PGT Expansion Project (Case 2) will lead to lower per unit netbacks compared to a situation where no incremental pipeline capacity from Alberta into California is constructed. This result suggests the Midwest market is a more attractive market than those served by the PGT expansion. The PGT Expansion Project will also result in a substantially lower levelized netback than the Altamont/Kern River Project ($0.65/GJ vs $1.55/GJ). In fact, Altamont's conclusion indicates that adding Altamont to the PGT Expansion Project (i.e. case 4 above), raises the overall levelized netback to $1.03/GJ (1991 C$). This is still below the opportunity price benchmark of $1.25/GJ, but better than the PGT Expansion Project alone.[74]

The PGT Expansion Project turns out to be less attractive for Alberta producers than the Altamont/Kern River Project for three main reasons:

1. It will cause a shift in the California supply.

2. It will erode the netbacks to existing A&S shippers serving northern California on the existing PGT system.

3. The PGT filed tolls were adjusted upward by Altamont.

According to Altamont, the PGT Expansion Project, coupled with the inevitable Kern River expansion will introduce enough new gas into the California market to displace Permian gas as the marginal supply source. Altamont assumes that a minimum of 500 MMcf/d of gas must flow to California from a basin in order for that basin to qualify as the marginal supply.

Recent southwest expansions to California on the El Paso and Transwestern systems from the San Juan Basin have displaced Permian gas. By the proposed start-up date of the PGT Expansion Project and Kern River expansion in November 1993, Permian gas will be supplying about 919 MMcf/d to California. Upon start-up of the PGT Expansion Project in conjunction with the inevitable Kern River expansion in November 1993, further volumes of Permian gas will be displaced. As a result, Permian will supply less than the 500 MMcf/d assumed minimum requirement.

This instantaneous supply displacement will shift the California marginal supply to the lower priced San Juan Basin. The size of this price drop in 1993 will be approximately $0.20/Mcf(US). This supply shift will remain in effect until 1999 when Permian gas re-enters the California market above the assumed minimum of 500 MMcf/d. Permian gas will re-enter because of assumed growth in California gas demand.

Altamont emphasizes that even if Kern River is not expanded or is expanded later, the relative results would not change. The only difference will be that Permian gas will re-enter California sooner, in 1995. This will increase the PGT levelized netback but it would still be inferior to the Altamont levelized netback.[75]

The second factor that leads to Altamont's conclusion is its adjustment of PGT tolls, described in other sections of this report, which raises the projected tariff to southern California by over 40 per cent relative to PGT's own version.[76]

The third major factor, erosion of existing A&S shippers' netbacks is rationalized as follows. Competitive market forces dictate that gas prices at Topock, Kern River Station and Malin shall be equal. However, the CPUC's crossover ban on the PGT Expansion Project could result in two prices for Canadian gas at Malin: one, a northern California price for existing A&S volumes which approximately equals the Topock price; the other a southern California price for the PGT Expansion Project volumes equal to the Topock price less the PG&E's expansion toll to northern California. More specifically, there will be one price for existing A&S shippers at Malin set at $2.00/Mcf and another price netted-back from Kern River Station equal to $1.33/Mcf at Malin (net of adjusted tolls on PG&E).

Even under the assumption that the cross-over ban is maintained whereby PG&E customers are not allowed to use the existing firm capacity to buy from the expansion shippers at Malin, Altamont is of the view that the CPUC will not tolerate this "conceptual" difference in the Malin prices. It will, therefore, exert pressure on A&S shippers to reduce their netbacks to reflect expansion netbacks of $1.33/Mcf at Malin. Even in the absence of CPUC pressure, competitive forces could cause the A&S price at Malin to fall. Altamont believes that, in this instance, existing consumers will force A&S shippers to accept netbacks in line with those of expansion shippers.[77]

Sensitivity Analysis

Altamont also examined other cases to determine the sensitivity of the results. These cases used the PGT tolls as filed with FERC; a California demand forecast midway between Altamont's and the California Gas Report; a higher Gulf Coast price forecast; and higher minimum volumes for Permian, to qualify as the marginal supply basin. The results of this sensitivity analysis did not alter the relative comparability of the projects outlined above.[78] Altamont alone will still generate the highest netback, Altamont-PGT together will be the next best scenario, while PGT alone will be the worst.

4.6.2 PGT View of Altamont Netback Analysis

PGT questions Altamont's use of the opportunity value concept to price Alberta gas, especially the volume differential between the PGT Expansion Project and Altamont/Kern River Project. Opportunity value can be used only if there is an actual opportunity to move this differential volume to an alternative market. PGT questions the availability of pipeline capacity to facilitate flowing the differential volume of 184 MMcf/d to the Midwest market. This transportation capacity to the next best market, the US Midwest, is currently not available.[79]

Another area of concern to PGT is Altamont's assumed load factors for the Altamont/Kern River Project. The assumed 95 per cent load factor for the Altamont/Kern River Project contradicts statements, made by Altamont in front of the FERC, in support of a 90 per cent load factor, instead of the current 95 per cent load factor, for rate purposes. The request was based on Altamont's testimony

that the maximum stand-alone throughput performance level on the project is 92 per cent. As well, Altamont's reliance on Kern River and NOVA may reduce operational availability to as low as 83 per cent. Under these circumstances a 90 per cent load factor, for rate purposes, would be appropriate. PGT notes that this undermines the use of a 95 per cent load factor in the Altamont analysis.[80]

PGT also questions Altamont's upward adjustment of PGT's filed tolls. Altamont stated that each adjustment is a possibility but it is unlikely that all of them will occur.[81]

Altamont's modelling of the volume displacements of California supplies is also disputed. PGT argues that it will be unlikely that marginal supplies switch instananeously from one basin to another. PGT does not agree that its expansion will cause price degradation while Altamont will not; neither will different price impacts be expected because one project enters southern California and the other enters northern California.[82]

PGT questions Altamont's assertions that the Kern River Expansion will be built even without Altamont, since the FERC stated as recently as January 1992, that no Rocky Mountain suppliers have asked for extra capacity on Kern River. PGT concludes, therefore, that there is reason to believe that there will not be sufficient volumes of Rocky Mountain gas available to Kern River in the next 15 to 18 months to warrant expansion. Therefore, no supply shift due to the PGT Expansion Project will take place.[83]

4.6.3 PGT Netback Analysis

Summary of Results

PGT concludes that its expansion will result in total incremental revenues to Alberta producers of \$23.3 billion (1991 C\$) over the period 1993-2013, compared to \$17.6 billion (1991 C\$) to be generated if Altamont is to be built instead. Assuming a 10 per cent discount rate, the Expansion will result in 20-year levelized netbacks of \$2.87/GJ to \$2.95/GJ(1991 C\$). The lower result assumes rolled-in tolls for the Canadian portion of the expansion with incremental tolls for the US portion. The higher result assumes rolled-in tolls for all portions of the expansion except PG&E's California portion, where incremental tolls are assumed for southern California deliveries. The comparable netback for the Altamont/Kern River Project alone is \$2.56/GJ(1991 C\$).

PGT's Base Case results outlined above give the PGT Expansion Project an average netback advantage of \$0.39/GJ(1991 C\$) over the Altamont/Kern River Project.[84] This result assumes rolled-in tolls for all portions of the expansion, except PG&E tolls into southern California, and covers the period 1993-2013. The reasons for this base case result are:

1. PGT has access to the northern California and Pacific Northwest markets. The proximity of these markets, lower tolls, and higher average citygate prices give the PGT Expansion Project a netback advantage.

2. Altamont transports smaller volumes than PGT to southern California and relies heavily on markets in the Midwest and Rocky Mountain regions. PGT believes netbacks from these markets will be substantially lower than those available from California and will result in lower average netbacks on Altamont.

Description of Methodology

The analysis that generated these results relies on the North American Regional Gas Supply Model (NARG). The NARG model attempts to simultaneously maximize producer value at the wellhead and minimize consumer costs at the burner tip throughout North America to find market clearing quantities and prices. The NARG analysis examines the order of competitive supplies available to California and the economics of gas flows between supply basins and California.

The first result of the NARG analysis is PGT's ranking of the order of competitive supplies available to California from low-cost to high cost as follows: tax advantaged San Juan coalbed methane, existing Alberta supplies, new Alberta supplies via the PGT Expansion Project, Rocky Mountain gas via Kern River, and Southwest Conventional gas (Permian, Anadarko and San Juan). Supplies from the Southwest, being highest in cost, are the marginal, price determining supply in the California market.

The second result is that Altamont's project will not be economically viable. The basis for this conclusion is that Altamont will be moving gas to the Opal, Wyoming area, where abundant supplies of Rocky Mountain gas are available to move to California via Kern River. The costs associated with moving Alberta gas to this region will put it in direct competition with Rocky Mountain gas (i.e. the prices of the two streams will be roughly equal at this point). This, PGT concludes, will have serious implications on the ability of Alberta gas to move to California via Kern River. As well, PGT questions whether Alberta gas can compete in any of the alternative markets accessible from Opal, including the Midwest and Rocky Mountain states (Montana, Wyoming, Colorado, Utah and Nevada). Consequently, PGT metaphorically describes Altamont's project as one which "carries coal to Newcastle".[85]

WMR's netback model adopts the results of PGT's NARG analysis. Therefore, WMR accepts PGT's sequence of competitive supplies and conclusions regarding the Altamont and Kern River Projects. WMR assumes that Kern River will not be expanded without Altamont. The netback model simply subtracts transportation costs from citygate prices to arrive at a value of gas at the Alberta border and plantgate.

The forecast of annual citygate prices is based upon The Gas Research Institute's (GRI) 1992 Baseline Study. Using this forecast, PGT indicates that equilibrium prices in California are not equal because the higher percentage of core market in northern California ensures higher prices relative to the south. Furthermore, even with a crossover ban, tolls for expansion gas to northern California will be cheaper than to southern California because of a "backbone credit" of $0.11/GJ(1991 C$).[86] Expansion gas will be diverted into northern California to take advantage of higher netbacks of $.30/GJ over the life of the project. PGT assumes capacity deficits in northern California will further support this price differential.[87]

PGT assumes the PGT Expansion Project will transport 903 MMcf/d, of which 755 MMcf/d are destined to California (two-thirds to southern and one-third to northern California) at an 85 per cent load factor, and 148 MMcf/d are Pacific Northwest volumes transported at a 70 per cent load factor. For the Altamont/Kern River Project, PGT assigns 452 MMcf/d of Altamont's capacity to southern California at an 85 per cent load factor, and the remaining 267 MMcf/d to Altamont's alternative markets in the Rocky Mountain states and the Midwest at a 70 per cent load factor.

PGT used tolls as filed for the netback assessment of its expansion and the Altamont/Kern River Project. Two possible toll methodologies were used for the PGT Expansion Project though:

1. rolled-in Canadian rates; or

2. rolled-in rates as far as Malin (Canadian and PGT rates).

PGT assumes the net effect of either roll-in or incremental cost allocations on the PGT Expansion Project would be the same from a total industry perspective. Increased tolls on the existing system would be offset by decreases on the expansion.[88]

Analysis of Results

PGT examined two cases using the results from the NARG analysis. The two cases were:

1. the PGT Expansion Project proceeds; or

2. the Altamont/Kern River Project proceeds.

The analysis made no attempt to explore the consequences of both projects proceeding. The key assumption used by PGT was that in the event of the PGT Expansion Project, Kern River will not expand. Therefore, Permian gas has no threat of being displaced to the extent that the California market price will be eroded.

PGT emphasized that its expansion will have access to northern California, while Altamont does not. This will have a substantial positive impact on PGT's average netbacks because of northern California's higher percentage of core market relative to southern California and lower tolls for expansion volumes destined for northern California. The higher percentage of core market translates into higher average citygate prices. This fact, coupled with a $0.11/GJ(1991 C$) "backbone transmission credit" on PG&E, constitute the positive netback factors of the northern California market. Furthermore, PGT assumed this higher percentage of core in northern California will persist over the 1993-2013 period. Therefore, netbacks from northern California are about $0.30/GJ(1991 C$) higher than from southern California, for the PGT Expansion Project, over the whole forecast period.

Altamont's reliance on the Midwest and Rocky Mountain markets results in lower average netbacks. PGT indicates that in 1994, for example, netbacks from these markets will be 54 per cent and 75 per cent, respectively, of southern California netbacks. Furthermore, PGT contends that the Altamont/Kern River Project will have only 452 MMcf/d of capacity into southern California via Kern River expansion, with the balance to serve lower netback markets. PGT's system, in contrast, will have 755 MMcf/d of capacity into California. Altamont's inability to move higher volumes into California because of the Kern River bottleneck will serve to lower its shippers' average netbacks substantially.[89]

Sensitivity Analysis

PGT modified some of its assumptions to determine whether its calculated Base Case netback advantage over Altamont of $0.39/GJ(1991 C$) is robust. These modifications pertain to Altamont's capital costs, capacity deficits in northern California, and gas demand in southern California.[90]

PGT believes Altamont's capital costs could be understated by as much as 22 per cent. If the higher cost estimate should prove accurate, Altamont's netbacks could fall on average $0.07/GJ(1991 C$). This would have the effect of raising PGT's overall netback advantage to $0.46/GJ(1991 C$).

PGT believes that currently there are capacity deficits in northern California and capacity surpluses in the south. It suggests, therefore, that the probability is high that some PGT volumes will be diverted to northern California, above those in the base case results. For every 50 MMcf/d diverted from southern California, average PGT netbacks will increase by $0.02/GJ(1991 C$) because of higher citygate prices and cheaper tolls to northern California. Altamont's lack of pipeline capacity to northern California from the Kern River Station rules out any corresponding benefit to its shippers from such a market opportunity.

PGT believes Altamont's demand projections for southern California are too high. It indicates most other outlooks project lower southern California natural gas demand. As a result, lower than expected load factors for gas destined to California are a very real possibility on Altamont. For every 50 MMcf/d shortfall in volumes transported on Altamont, average netbacks to Alberta would fall by $0.05/GJ(1991 C$).

The possibility that Altamont could transport volumes on the existing Kern River system is also examined by PGT. If the unusually high gas demand projections made by Altamont did materialize, a case might be made for Alberta gas displacing some Rocky Mountain gas moving on the existing Kern River facilities. PGT indicates that shippers on the existing Kern River system could substitute up to 87 MMcf/d of Alberta gas for Rocky Mountain gas. PGT's results indicate that, for every additional 50 MMcf/d of Alberta gas reallocated to southern California, the average netback for total Altamont volumes increases by $0.05/GJ(1991 C$).

PGT believes that the effect of these sensitivity results together, could substantially raise PGT's advantage to well above the $0.39/GJ under the base case.

PGT considered the effects of lower and higher citygate prices along with lower and higher load factors on both projects and found its margin of advantage did not change.

PGT identified further risks facing Altamont without quantifying them. In PGT's view, failure of sufficient non-California markets to materialize to the extent required may threaten the project's commercial viability. There is a serious possibility that low load factors could result such that a sufficient return on equity and income tax may not be recovered through commodity charges. Although its own project also faces unresolved rate design issues, PGT indicates the risks to its expansion are not great enough to offset its $0.39/GJ(1991 C$) advantage over the Altamont/Kern River Project. PGT also addressed Altamont's argument that the PGT Expansion Project will cause California citygate prices to fall. PGT states that there are no credible arguments as to why one project would have this effect while the other would not, particularly given the view that Kern River is unlikely to expand without Altamont.

4.6.4 Altamont View on PGT Netback Analysis

Altamont believes that PGT tolls are exposed to a number of risks (see Section 4.4.4). In Altamont's estimation, PGT tolls will inevitably be higher than currently filed rates. This will seriously erode any PGT netback advantage, as will the negative price impact that its expansion will have in California. Altamont emphasized that Kern River will expand its system with or without Altamont. The impact of

Kern River and PGT together will cause Permian-Anadarko supplies to be displaced, therefore driving down California prices. Netbacks will be eroded as a result.

Altamont insists that the PGT Expansion Project will result in lower netbacks for existing A&S producers. If the expansion costs do get rolled-in, then transportation rates for existing shippers will increase. Under an incremental rate structure, however, the fact that shippers using the PGT Expansion Project would accept lower netbacks on gas travelling the same route to northern California would give the CPUC a powerful weapon to pressure PG&E to insist on lower netbacks on all volumes of Alberta gas.

Altamont disputes PGT's proposition that cost reallocations between its expansion and the existing shippers amount to a net zero sum game. If end-users however, hold capacity on only the existing PGT system, then the zero sum game argument does not apply, nor would it be applicable to any capacity arrangements that do not rely on netback pricing. Altamont used the example of PITCO. PITCO currently has firm capacity on the existing PGT system and is purchasing gas at Kingsgate. The effect of an incremental cost allocation, for example, would lower tolls on the existing system. This benefit would not accrue to Alberta producers vis a vis netbacks, but would accrue instead to PITCO. Therefore, Altamont argues that failure to analyze these potential netback impacts skews the analysis in favour of PGT.[91]

Altamont also questions PGT's northern California assertions. Altamont noted that PGT's results show a $.30/GJ(1991 C$) differential in favour of northern California netbacks, throughout the whole 20-year period. This differential is due to two factors: (1) higher average citygate prices in northern California, and (2) lower tolls to northern California. Altamont questioned the rationale for the persistence of this differential given PGT's assertion that gas would likely be diverted to northern California because of capacity deficits. A narrowing of this differential, over time, would seem to make more economic sense.[92]

PGT indicates that the PGT Expansion Project's total net revenue accruing to Alberta is 41 per cent higher than Altamont. Altamont notes that roughly half of this differential is due to higher projected volumes on PGT. Altamont is of the view that the benefits of the projects should be compared on an equal volume basis since total revenue generated will be skewed in favour of the project that moves larger volumes.

4.6.5 Comments on the Proponents' Netback Analyses

While the Board appreciates the complexity of the issues that both parties have attempted to model in assessing the impact on western Canadian producer's netbacks, the Board notes that the different conclusions are a result of the use of quite different assumptions. The Altamont and PGT studies each make assumptions favouring their own project. Given that, readers should consider carefully how much weight should be attached to the conclusions of either one.

For example, Altamont's contention that its volumes will not have an impact on intra-California gas pricing since Kern River's expansion would proceed even in the absence of Altamont, is open to question. Kern River testified that without Altamont, it is prepared to solicit interest in an expansion of its system and determine the level of support such an expansion would have. At present, no support has been identified.

Similarly, PGT's contention that its expansion will have no net effect on existing netbacks from sales into California is also open to question. The availability of increased supplies of gas to satisfy a relatively stable demand could put downward pressure on prices, particularly in a market with potential for displacement sales. The latter point suggests an impact on prices could occur regardless of the point at which expanded capacity enters the market. Either project could affect netbacks.

Apart from the uncertainty accompanying forecast natural gas prices in California, the absolute level of netbacks proposed by both PGT and Altamont should be assessed with all the uncertainties in mind. Two specific uncertainties relate to capital costs and eventual regulatory decisions. Moreover, to the extent that either project operates at less than projected load factor, then producer netbacks will be reduced accordingly.

4.7 DESCRIPTION OF THE TRANSPORTATION COMMITMENTS ON THE PROPOSED FACILITIES

4.7.1 ANG-Foothills

ANG has entered into firm transportation agreements with 27 shippers totalling a maximum volume of 930.15 MMcf/d. The minimum length of these contracts is 15 years. These arrangements are irrevocable, long-term commitments conditional only on ANG'S expansion being brought into service on a timely basis. There are no other agreements that modify or otherwise materially change the commitment. As a result of a project agreement between ANG and each of the expansion shippers, the latter are under no obligation to begin paying demand charges if ANG's expansion is completed before PGT's. No such waiver, however, was provided by ANG with respect to the upstream NOVA service availability date. The shippers have the right to terminate their contracts with ANG if PGT terminates its agreement with the shippers. The contracts are subject to all valid legislation with respect to subject matter either provincial or federal.

4.7.2 PGT

PGT has entered into firm transportation agreements with 27 shippers for firm capacity of 900.57 MMcf/d. These agreements were made pursuant to Section 7(c) of the Natural Gas Act. The initial term of the majority of the contracts is 30 years in length (except for two at 16 years in length and one at 20 years). After the duration of the agreement during which the contract is irrevocable, service will continue from year to year, subject to cancellation on 12 months notice by the shipper. The firm service transportation agreement is subject to all valid legislation with respect to the subject matters, either state or federal and to all valid present and future decisions, orders, rules, regulations and ordinances of all duly constituted governmental authorities having jurisdiction. Shippers are obligated to pay tolls if PG&E is not completed before the given start-up date.

4.7.3 PG&E

PG&E has entered into firm transportation service agreements with 16 shippers for firm capacity totalling 572.30 MMcf/d[93] and is currently negotiating with 6 other shippers. To avoid prejudice, all executed contracts are filed confidentially with CPUC. The execution of these contracts has been complicated by the pendency of CPUC's rehearing on PG&E's rate design (decision is expected by spring 1992). For this reason, the contracts that have been executed do provide for possible renegotiation in the event the outcome of the CPUC's proceeding materially affects the shippers' service. However, PG&E retains the right to enforce the shippers' obligation to pay demand charges

for firm transportation over the term of contracts. Contracts executed to date with PG&E have been for terms equivalent to shippers' commitments to PGT.

4.7.4 Altamont

Altamont has entered into agreements with 14 shippers who have reserved firm capacity of 718.8 MMcf/d on the system. Each shipper has signed a Precedent Agreement and a Firm Transportation Agreement.

The Precedent Agreement stays in effect until service commences under the firm transportation agreement. Both Altamont and the shipper have the right to cancel the arrangement on 30 days notice if the following "conditions precedent" are not satisfied:

1. Altamont and shipper obtain all the necessary authorizations.

2. Shipper arranges upstream and downstream transportation.

3. NOVA and Kern River expansions are authorized. Under the terms of the agreement, Altamont is entitled to ask the shipper to either exercise its termination rights or waive them within 30 days of a final FERC approval or 60 days prior to Altamont placing its pipe order, whichever comes later. Altamont can cancel on 60 days notice if it cannot arrange satisfactory financing or shipper's agreement. Altamont is to use its best efforts to match the timing of NOVA and Kern River. Under the conditions of the Firm Transportation Agreement, the length of the term is 15 years from commencement of service. The term can be extended from year to year thereafter, and is subject to cancellation with 12 months notice by either party. Rates are payable only when both Altamont and the expanded Kern River are in-service.

4.7.5 Kern River

Kern has entered into Transportation Service Agreements with 9 shippers on its expansion system for firm capacity totalling 451.76 MMcf/d.

The length of the Transportation Service Agreements is 15 years from the latter in-service dates of Altamont and the Kern River expansion. PIC's agreement has specified an in-service date which includes the SoCalGas facilities. The shipper's commitment to pay demand charges is firm, as even a claim of force majeure by either party does not relieve the shipper from its obligation except in very limited circumstances. Kern River has agreed to keep its rate constant for 15 years even if an Altamont shipper reduces his maximum daily quantity.

4.7.6 Other Interconnected Pipelines

Of the 14 shippers who have Firm Transportation Agreements with Altamont, 9 have similar agreements with Kern River. Of the 5 shippers with no capacity on the Kern River expansion, Conoco Inc. has existing interruptible transportation agreements on Northwest, CIG, Kern River and Questar. The remaining shippers are currently pursuing market opportunities.

4.7.7 Comments on Transportation Commitments

To date, shippers on the PGT Expansion Project have shown a greater level of commitment, as these shippers have signed irrevocable long-term contracts. In contrast, shippers on Altamont have signed, in addition to a Firm Transportation Agreement, a Precedent Agreement, which gives them an opportunity to leave this project until firm service commences.

4.8 STATUS OF PROJECT FINANCING

4.8.1 Altamont/Kern River Project

Altamont asked First Boston Corporation (First Boston) to assess the feasibility of Altamont's financing plan for the pipeline system. First Boston is an investment banking firm engaged in all aspects of underwriting business and in the distribution of securities. The sponsors chose project financing as the mechanism to raise capital. The basic elements of the Altamont financing plan are:[94]

- Upon commencement of operation, Altamont will have a capital structure consisting of 75 per cent debt and 25 per cent common equity.

- Necessary debt capital will be obtained on an interim construction basis either through bridging loans from commercial banks or through the issuance of commercial paper. These short-term obligations will be refinanced with longer-term debt upon completing the pipeline.

- The credit-worthy parent companies of their shareholders will provide completion assurances until the pipeline is in service.

- Once the pipeline is operational and the gas transportation agreements and tariffs have become effective, the lenders will rely exclusively upon the Altamont contracts with its shippers and not on the assets or cashflows or the sponsors or their affiliates. First Boston concluded that the Altamont financing plan is sound and that the required debt capital can be obtained on a timely and cost-effective basis.

Altamont believes that as long as there is 350 to 400 MMcf/d firm market for gas flowing on its system, financing the project would be economically feasible from the banker's perspective.

Kern River's expansion will be financed by way of limited recourse project financing. The total project cost will be funded 30 per cent by equity from the partners of Kern River and 70 per cent by debt. After certification by FERC, equity and short-term debt will fund construction. Upon completion, all short-term debt will be converted into permanent financing through the offering of long-term securities. These securities are expected to be retired over the 13 years subsequent to the in-service date.

4.8.2 PGT Expansion Project

ANG's project costs such as engineering and design studies, supply studies and regulatory costs as well as other ongoing expansion activities are currently funded through ANG's cash flow. Facilities construction commitments will be funded through general corporate financing. ANG's actual term and method of financing will be finalized early in 1992. Foothills has had preliminary discussions with its lenders and does not anticipate difficulty in raising required capital.

PGT and PG&E's Expansion will be financed initially with 30 per cent equity and 70 per cent debt. PG&E is financially able to meet the equity funding requirement. Funds borrowed under PG&E's ongoing utility financing program will secure capital for the debt side. PG&E is rated single-A by the major bond rating services which gives the utility ready access to public debt markets. Interim debt funding to PGT's expansion was obtained from a group of six banks (US$ 200 million). The long-term debt portion of capital requirements will be raised on a project financing basis, if possible (i.e. without ongoing recourse to PGT's owner after project completion). PGT does not anticipate any difficulties in debt availability on reasonable terms and at an acceptable cost.[95]

At the oral examination, Altamont raised several issues that might affect PGT's financing.[96] Such issues include absence of final orders out of the FERC, absence of full shipper subscription on PG&E's portion of the expansion, issues raised in the Line 300 expansion proceedings before the CPUC, absence of export and provincial removal permits, and the proposed sale of PGT to TransCanada Pipelines Limited (TCPL).

PGT, in its response to Altamont's claims, indicated that it is routine that the FERC has its orders tolled (delayed) and that lenders then examine the issues that are tolled and make judgement as to their significance. In terms of the issues that are subject to rehearing for PGT, there are two that do not affect the lenders materially; one is the return on equity and the other is permanent versus changing throughput. The latter, in PGT's view, is of no real significance to lenders because of PGT's straight fixed variable rate design.

PGT responded to the issue of lack of shippers' full subscription on PG&E's expansion by stating that this is not an issue at all since PG&E will finance its project completely with corporate debt.

While PGT acknowledged that one of the cases to be considered in the Line 300 Expansion proceeding is a no PGT Expansion Project case, in its view this is not a useful exercise given that the expansion is already under construction and that the CPUC is continuing to give authorization to move forward.

PGT is of the view that its shippers have the requisite reserves data and contractual commitments to support granting them export authorization from the NEB and removal permits from this Board.

PGT stated that the nature of permanent financing of the expansion hinges somewhat on the outcome of the proposed sale of PGT to TCPL. Depending on when this might occur, one sponsor or the other (PG&E or TCPL) would probably have to provide some level of recourse.

4.8.3 Comments on Project Financing

Straight project financing is less certain than financing backed by a financially viable sponsor. Both pipelines will require completion guarantees from sponsors, so the financial health of sponsoring companies is relevant. The final terms of the project-based financing will not be settled until after key regulatory decisions are made.

PG&E's expansion will be financed corporately; to the extent that PGT's borrowing is backed either by PG&E or TCPL, financing for the expansion project should be easier than if full project financing is required.

The Altamont/Kern River Project faces somewhat greater uncertainty, since the intention is to borrow fully on a project basis.

In general, there are many risks to the financeability of both projects. To the extent that these risks affect the cost of borrowing, there will be an impact on transportation rates.

4.9 POSSIBLE ALTERNATIVES TO ADDING INTERSTATE CAPACITY

4.9.1 Expansion of PG&E Line 300

In late February 1992, the CPUC held a prehearing technical conference to consider whether there are further supply alternatives available to northern California. At this proceeding, PG&E was asked to evaluate an expansion to Line 300 up to 600 MMcf/d to carry more US southwest gas to market as an alternative to its current plans to expand Line 400 to access more Canadian supplies. PG&E estimates that an increase to Line 300 by 600 MMcf/d would cost $419.4 million (1992 US$). During oral examination before the Board, however, PGT indicated that it did not consider additional capacity on Line 300 as a viable alternative, despite the fact that this line may be expanded at a lower cost. This is because PGT views the Canadian supply basin as more competitive than southwest US gas supply, in serving the California market. According to PGT, the existing infrastructure already maximizes the potential to bring in the low-cost tax-subsidized coal-seam methane production from the San Juan Basin.[97] Apart from the question of access to low-cost supplies, PGT also indicated that a substantial expansion of Line 300 would require a lead time of around 4 years, while the California need for additional supplies is more immediate.

Altamont notes that there already exists some stranded capacity at the Arizona border and an expansion of Line 300 would be an obvious means of bringing that capacity north. To the extent that such an expansion would be economical, Altamont alluded to engineering data presented by PG&E in 1986 where it calculated an expansion of Line 300 by 250 MMcf/d would cost around $75 million dollars (US). In addition, Altamont suggested that its project could serve northern California even more efficiently than expanding Line 300, as it delivers gas all the way to Kern River Station and, thus, PG&E would only be required to expand its system north of Kern Station.[98]

4.9.2 Additional Storage Capacity

As an alternative to additional expansions to interstate pipeline capacity to meet peaking needs, PG&E has been asked by the CPUC to consider additional storage capacity. In response, PG&E estimated that costs would range from $33.4 million (1992 US$) for 5 Bcf to $200.7 million (1992 US$) for 50 Bcf. PG&E identified McDonald Island as the only area where there is any potential for the expansion of storage, and notes that this facility can only be supplied by either Canadian supplies via Line 400 or indigenous California supply. PGT contends that, as Canadian gas is the only incremental supply available to this facility, any significant expansion to storage would necessitate an expansion to Line 400 in the order of 100 to 200 MMcf/d. PGT does not, however, envisage building a storage capacity so large that it would replace a 755 MMcf/d expansion of Line 400.[99]

Altamont has a very different view of the facilities needed to add additional storage capacity in northern California. Noting that around 29 Bcf was withdrawn from McDonald Island in 1990, Altamont asserts, all that would be needed to achieve an additional 30 to 40 Bcf would be to add some compression and injection wells.[100] Altamont submitted that Kern River will capture a

significant portion of PG&E's existing market and, therefore, free up anywhere from 200-500 MMcf/d of interstate capacity to meet peak demand directly and supply expanded storage facilities.

4.10 ENVIRONMENTAL AND SAFETY CONCERNS

Altamont

In the proceedings leading to the issuance of a Certificate of Public Convenience and Necessity to Altamont, FERC conducted an extensive environmental review pursuant to various Environmental Acts and Statutes and concluded that Altamont is environmentally acceptable.[101]

As a result of a Cultural Resource Survey, Altamont has identified a number of locales along its proposed route that may require listing in the national register of historical places. Mitigation of these sites is currently underway so that Altamont is confident of obtaining notice from the FERC to proceed on mainline construction by April 1993.

Altamont has included amounts in its cost estimate to provide for safety and environmental concerns. These concerns have also been incorporated into the project schedule.

Kern River

As part of its application to FERC for the certification of the proposed expansion, Kern River filed an environmental report prepared in accordance with FERC's regulations and guidelines. The report addresses not only environmental and socio-economic impacts but also reliability and safety issues relating to the construction and operation of the proposed facilities.[102]

As these facilities will be primarily additional compression with a limited amount of pipeline looping, the environmental impact would be minimal. The cost associated with implementing required mitigation measures has been included in the estimate of the total project cost.

ANG-Foothills

In its "Reasons for Decision" GHW-2-91, the NEB concluded that the potentially adverse environmental effects which may be caused by the construction and operation of the applied-for facilities would be insignificant or mitigable with known technology. Also, according to the BC Ministry of Environment, the ANG expansion is expected to operate well within BC existing regulations.

The Foothills expansion facilities will comply with the Environmental Terms and Conditions under an existing certificate issued pursuant to the Northern Pipeline Act. All environmental concerns identified can be mitigated using known technology.[103]

All known environmental and safety issues respecting ANG-Foothills have been accounted for and included in the project schedules. Therefore, no additional impact is foreseen for the timing of the proposed facilities.

PGT-PG&E

The PGT-PG&E portion of the expansion project has received extensive and comprehensive environmental review from both Federal and state regulatory authorities. The FERC prepared an Environmental Impact Statement (EIS) to satisfy the National Environmental Policy Act requirements and the CPUC prepared an Environmental Impact Report (EIR) to satisfy the California Environmental Quality Act.

The conclusion of both environmental reviews is that the PGT-PG&E portion of the expansion is environmentally acceptable. Both the EIS and EIR identify mitigation measures to minimize the environmental impacts for both the less-than-significant and potentially significant impacts. These measures were then certified by each representative Commission. In their mitigation measures, the FERC and the CPUC require that certain plans, programs, and schedules be provided for review and/or approval prior to the initiation of construction.[104]

Pipeline engineering is essentially complete and bids have been received for construction. Therefore, the potential for significant impacts to cost and schedule due to environmental and safety concerns is minimal.

Since the PGT-PG&E expansion is located in a region with higher geological disturbance activities, it would theoretically have somewhat higher risk associated with such activities than Altamont-Kern River. However, there have been no known major service interruptions to the existing PGT-PG&E transmission system because of earthquakes in the last thirty years.[105]

5.0 INTRA-ALBERTA PIPELINE FACILITIES

NOVA has executed a firm service transportation agreement for a 15-year term with Altamont for delivery of 737 MMcf/d of gas to the Alberta-Montana border at Wild Horse starting 1 November 1993. Similarly, NOVA has entered into an agreement with PGT and five of its customers for delivery of 829.4 MMcf/d of gas to the Alberta-BC border near Coleman. Irrevocable letters of credit have been arranged to cover costs incurred by NOVA during the first 8 months of 1992. With these and credit arrangements, NOVA has proceeded with design and equipment procurement for the projects.[106]

To meet delivery requirements of the Altamont/Kern River Project, NOVA's Intermediate Mainlines in the Peace River and North and East laterals and east Mainline to Empress would have to be expanded. The expansion would comprise a total of 72 MW additional compression and 210 km of looping, ranging in diameter from 10 to 48 inches. From Empress to Wild Horse, 200 km of 30-inch pipeline would have to be built.

To serve the PGT Expansion Project, a total of 71 MW compression is to be added to NOVA's Intermediate Western Mainlines to the Alberta-BC border, plus 160 km of looping, ranging in diameter from 10 to 42 inches.

For both the Altamont and PGT projects to proceed concurrently, NOVA would have to add 147 MW of compression to the Intermediate, East and West Mainlines, as well as 435 km of looping, ranging in diameter from 10 to 48 inches, and build the new 30-inch line from Empress to Wild Horse.[107]

In summary, facilities required for California gas expansion (PGT, Altamont or both) as described in NOVA's submission include mainline and intermediate mainline facilities only. Excluded are new meter stations and dedicated laterals supply connections, unless included in the 1992/93 plan filed with the Board in June 1991. The NOVA system has been divided into 3 areas:

1. Mainline;
2. Peace River; and
3. North and East Laterals.

The system design for Mainline areas downstream of the James River interchange is largely dependent upon the increased throughput associated with the downstream pipeline capacity of the Altamont and PGT projects. Such facilities are strongly affected by the total delivery-point capacity required and on the location of the delivery point(s). Peace River and North and East Laterals, on the other hand, are less sensitive to the specific downstream pipeline expansions. These represent intermediate mainline areas which are affected by the need to transport higher supply volumes to delivery legs.

5.1 INTRA-ALBERTA PIPELINE COSTS

In its submission, NOVA provides analysis for 4 different scenarios:

Case 1 or Base Case assumes no expansion into California;
Case 2 is Base Case + Altamont;
Case 3 is Base Case + PGT; and
Case 4 is Base Case + the 2 proposals.

What follows is a brief description of the costs of the facilities under each of these cases, all dollar figures being 1992 Canadian dollars as submitted by NOVA.[108]

Case 1 (Base Case)

Additional facilities are required to accommodate supply shifts as well as changes in interprovincial and other border deliveries. A total investment of $89 million is projected for the Mainline area. NOVA's facilities expansion to the Peace River area, absent any California expansion, is projected to total to $122 million for 1993/94 to meet the design flows for the Peace River area. Whereas, the forecast facilities for the North and East laterals will cost about $101 million.

So, facilities in the Base Case for 1993/94, absent expansion into California, will have a total capital cost of $312 million.

Case 2 (Base Case + Altamont)

This requires major facilities on the eastern Alberta system Mainline downstream of James River to the Empress border. Compression and incremental looping on the existing system are needed to meet the design flows. Total pipeline construction cost under this scenario is $503 million, while total compression is $294 million for a sum of $797 million, comprising all costs associated with facilities expansion for Mainline, Peace River and North and East laterals. The incremental cost associated with Altamont (net of what would have been required for expansion under the Base Case) is $485 million.

Case 3 (Base Case + PGT)

Major facilities will be required on the western Alberta system Mainline. Compression and incremental looping on the existing system is needed to meet the design flows. Investment requirements for Mainline, Peace River and North and East laterals are $303 million for pipeline, $311 million for compression to a total sum of $614 million. The incremental cost associated with PGT (net of what would have been required for expansion under the Base Case) is $302 million.

Case 4 (Base Case + PGT + Altamont)

Total investment requirement will be $689 million for laying pipe and $448 million for compression for a total of $1137 million. The incremental cost associated with the two proposed California expansions is $825 million.

5.2 IMPACT ON NOVA'S COST-OF-SERVICE

NOVA's unit cost-of-service is calculated using the system-wide, rolled-in rate design that is currently in effect. The unit cost-of-service for the Base Case is determined by dividing total annual cost-of-service by the forecast annual energy deliveries. Such deliveries result in a system average load factor of approximately 75 per cent, which corresponds to the total NOVA system average load factor.

The system unit cost-of-service under each of the 4 cases is calculated under alternative load-factor assumptions:

1. Incremental California deliveries under Cases 2, 3 and 4 will flow at a system average load factor of 75 per cent.

2. Incremental California deliveries will flow at a higher load factor of 85 per cent.

3. Incremental California deliveries will flow at a lower load factor of 65 per cent.

The results of the above sensitivity on the unit cost-of-service are depicted in Figures 5-1, 5-2 and 5-3 for the gas contract years starting 1993/1994 to 2012/2013.[109]

5.3 COMMENTS ON NOVA'S COST-OF-SERVICE

The system-wide unit cost-of-service under the PGT Expansion Project is less than under the Altamont-only scenario, since the PGT Expansion Project adds less to the total cost-of-service than Altamont (Case 3 vs. Case 2). The PGT-plus-Altamont case (Case 4) is also more favourable than Case 2 in terms of its impact on the unit cost-of-service, because of the additional volumes over which the total cost-of-service is applied. Using the higher load factor for incremental California volumes, Cases 3 and 4 are about equal. The PGT Expansion Project will cause NOVA's rolled-in toll to be at least 0.8¢ Cdn/GJ lower than under the Base Case for all shippers over the total forecast period, whereas Altamont/Kern River Project would increase NOVA's postage-stamp rate by 0.2¢ Cdn/GJ over the first 8 years of operation, assuming a load factor of 75 per cent for all movements into California. In subsequent years, the unit cost-of-service tends to be modestly lower under the Altamont-only scenario than under the Base Case at the current system average load factor, but will always be higher than the cost-of-service of the PGT-only scenario, by 0.8 to 0.9¢ Cdn/GJ.

5.4 ENVIRONMENTAL CONSIDERATIONS

NOVA will provide project-specific environmental information for the pipeline projects, with respect to routing considerations and environmental impacts, in pipeline permit applications to be submitted to the ERCB. Development and Reclamation applications, to be submitted to Alberta Environment, will contain detailed environmental information in respect to routing, environmental assessment, impact mitigation and environmental protection planning. Environmental information for compressor station projects will be included as part of the ERCB permit applications.

In the past three years, NOVA has gained considerable experience in mitigating the impact of large-diameter pipeline construction in all areas of Alberta where expansion of the NOVA system is projected to occur in response to the Altamont and PGT proposals. Consequently, NOVA believes that all impacts tied to the expansion of its system, by the Altamont and PGT proposals, can be mitigated satisfactorily.[110]

5.5 UPDATE OF NOVA COSTS

At the time of finalizing this report, NOVA filed with the Board its 1993/94 Annual Plan which includes revised cost estimates of the facilities required to accommodate the pipeline proposals. The majority of the costs associated with the 1993/94 facilities will occur in the 1993 calendar year. The updated costs estimates for the four cases considered are summarized in Table 5-1.

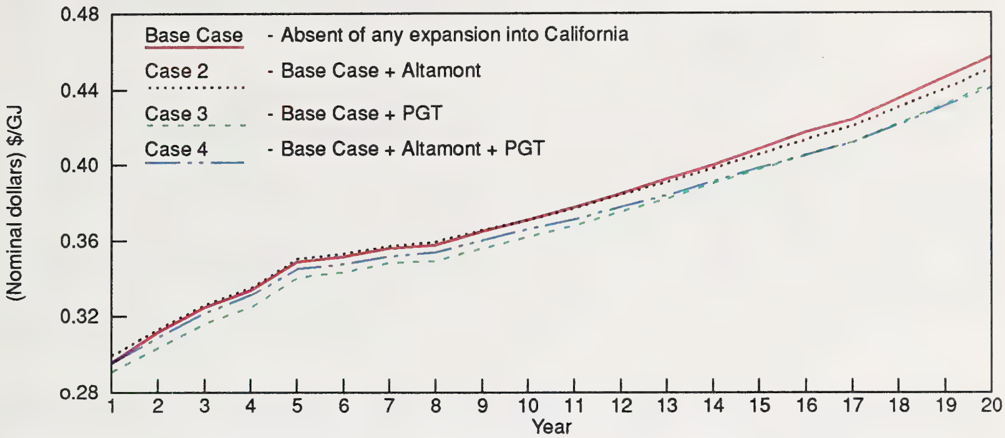

FIGURE 5.1 NOVA'S UNIT COST OF SERVICE. I.C.V.* @ System Average Factor (75%)

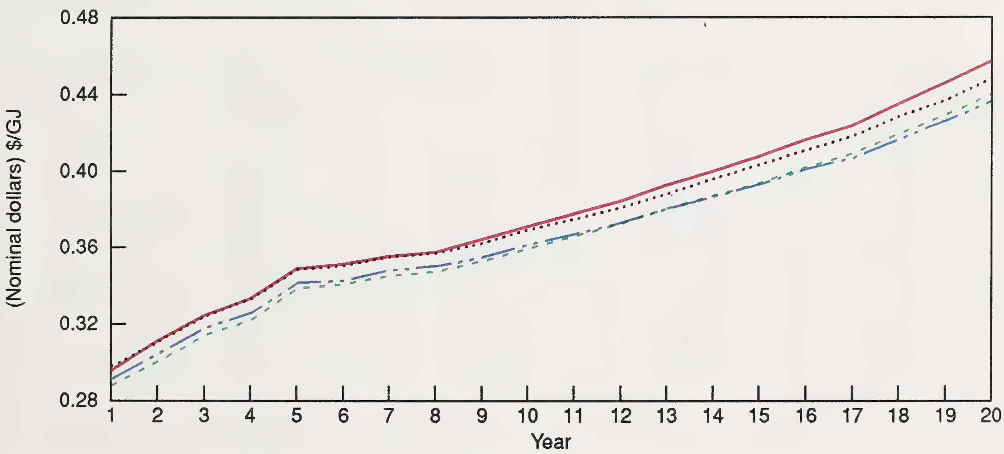

FIGURE 5.2 NOVA'S UNIT COST OF SERVICE. I.C.V.* @ 85% Load Factor

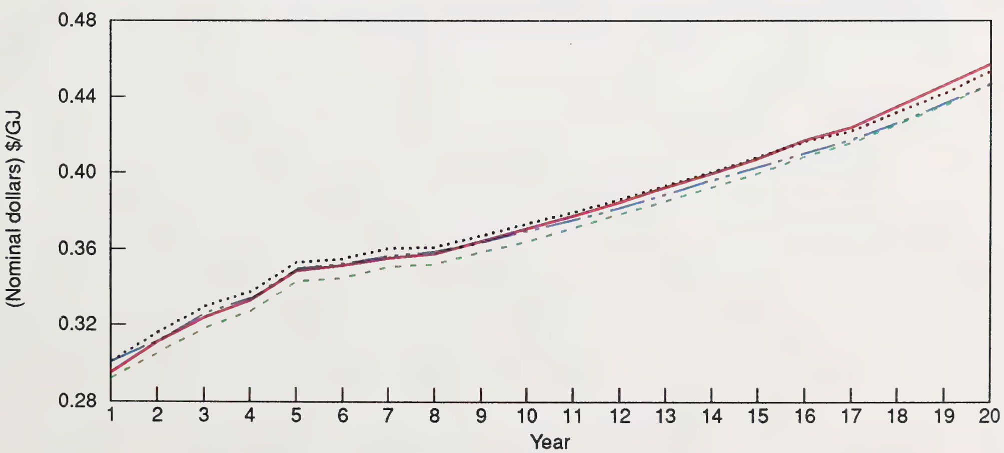

FIGURE 5.3 NOVA'S UNIT COST OF SERVICE. I.C.V.* @ 65% Load Factor

I.C.V.* - Incremental California Volumes

Table 5-1 Revised NOVA Costs of Facilities

	1993 Capital Cost ($ Million)
Both Altamont and PGT Projects as proposed.	775
Altamont only.	640
PGT only.	469
No California Pipeline Expansion.	400

Source: NOVA, 1993/94 Annual Plan, June 1992, page iv.

The corresponding cost-of-service impact over the period 1992 to 1999 are shown on Table 5-2.

Table 5-2 Revised System Average Unit Cost-of-Service Forecast (in nominal ¢/Mcf)

	PGT & Altamont	Altamont Only	PGT Only	No California Expansion
1992	28.9	28.9	28.9	28.9
1993	28.4	28.5	28.4	28.5
1994	30.1	29.6	28.6	29.5
1995	31.4	30.8	30.4	30.7
1996	32.9	31.7	31.6	31.7
1997	33.1	31.7	31.8	32.2
1998	34.2	32.9	32.8	33.2
1999	34.7	33.5	33.3	33.9

Source: NOVA 1993/94 Annual Plan, June 1992, pages 148-151.

It is, therefore, evident that the cost-of-service impact for the pipeline expansions into California is minimal.

6.0 GAS SUPPLY AVAILABILITY FOR PROPOSED FACILITIES

6.1 ALTAMONT

Through a study and analysis prepared by Coles Gilbert Associates Ltd., Altamont concludes that adequate supplies exist to support the Altamont/Kern River Project **or** the PGT Expansion Project over a 20-year period.[111] This conclusion is based on an assessment of overall gas supply in accordance with current ERCB policies and procedures respecting gas supply protection for Alberta. The Coles Gilbert study further concludes that there would be adequate volumes to supply **both** projects, but only if the Board exercises judgement as to expectations with respect to other relevant matters, such as future drilling activity and contracting practices. Also, Coles Gilbert concludes that since volumes currently approved are not being fully utilized, significant potential exists to utilize existing permit volumes to meet near term Altamont and PGT volume requirements.

In testimony, Altamont responded to a Board question concerning policies which could be employed if total Altamont and PGT requirements over 20 years exceed the amount of gas the Board calculates to be available for permitting.[112] Altamont's response suggested a policy which would place responsibility on the Board to make an evaluation of which project is in the Alberta public interest and award the removal permits to that project. This policy would only be used, however, if there is a concern at the Board that there is inadequate supply or inadequate market. If there is an adequate supply and an adequate market, the Board should, in Altamont's view, issue removal permits to both projects.

Altamont states that, currently, the Permian Basin and the Anadarko Basin provide the marginal supply of gas to California.[113] This source of marginal supplies will remain unchanged if the Altamont/Kern River Project proceeds, while the PGT Expansion Project does not. The sequence of supplies to satisfy California demand under this scenario is presented in Figure 6-1. Altamont believes that the Kern River expansion is inevitable even if its project does not materialize. For this reason, the PGT Expansion Project will cause a shift in the marginal supply basin to the lower priced conventional gas from San Juan Basin, as Figure 6-2 illustrates.

The status of contractual supply commitments for each shipper on the Altamont system are briefly described in Altamont's initial submission.[114] The information shows that arrangements have been made for a substantial portion of Altamont's total requirements, and that negotiations are proceeding for the remainder. A daily volume of 719 million cubic feet would be required to fill the proposed Altamont pipeline, or approximately 5.25 trillion cubic feet over a 20-year term. Expected supply sources for shippers on the Altamont pipeline, where identified, are listed in Appendix C.

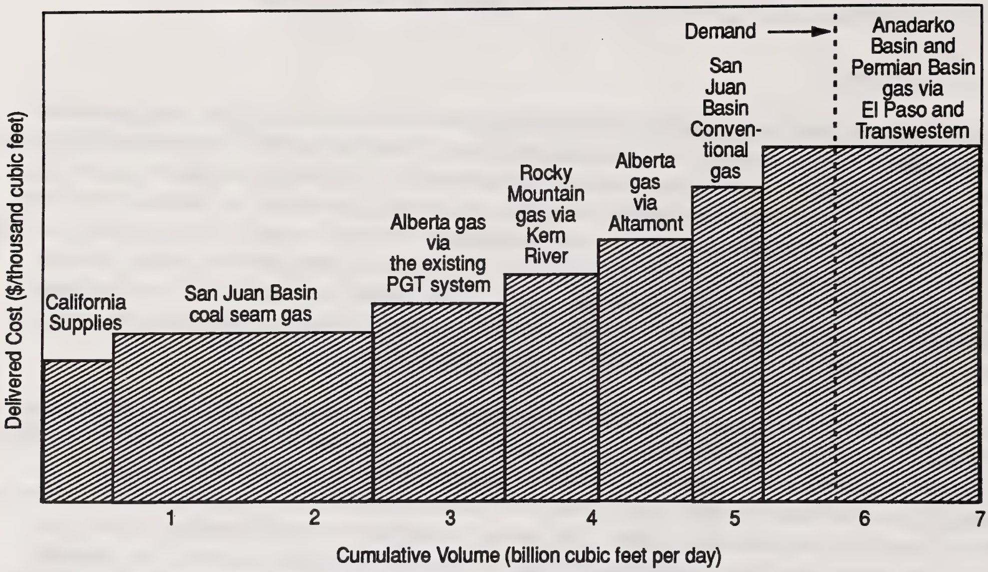

Figure 6-1 **Altamont View of Sequence of Supplies to California: Mid-1990s (with Altamont and without PGT/PG&E Expansion)**

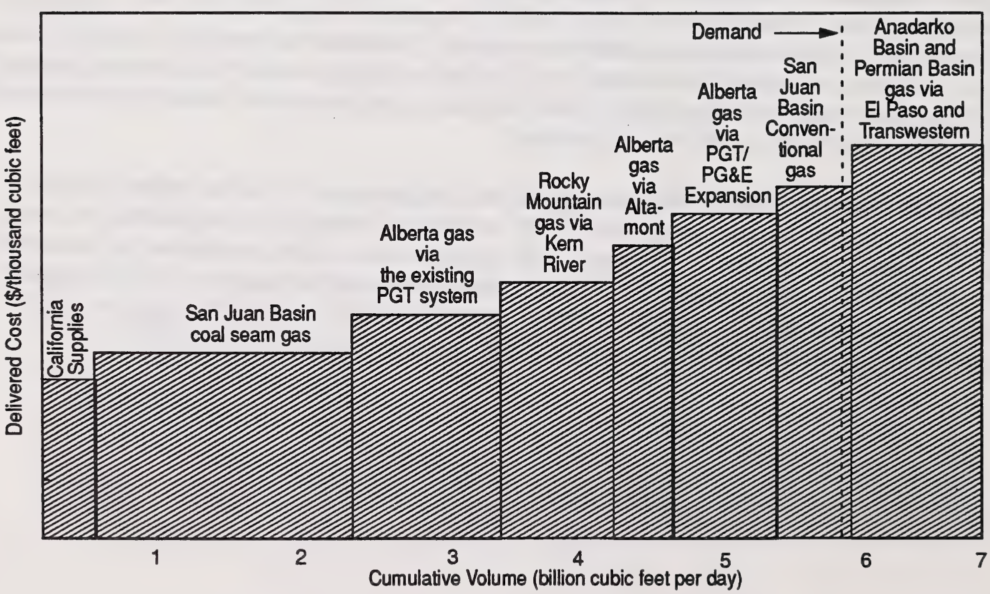

Figure 6-2 **Altamont View of Sequence of Supplies to California (with Altamont and PGT/PG&E Expansion)**

6.2 KERN RIVER

The "base" Kern River transmission system, placed in service during February 1992, is designed to transport 700 MMcf/d of gas from the Rocky Mountain area of the US, and from western Canada, to markets in California, Nevada, and Utah. The majority of Kern River's base system throughput will be sourced in southwest Wyoming and from US fields connected to Kern River by the systems of CIG, Questar, and Southwest.[115] Prior to completion of the Altamont project, western Canadian gas mainly from British Columbia, will supply some 180 MMcf/d of Kern River's base system throughput via the facilities of Northwest Natural, which interconnects with Kern River near Opal, Wyoming. After completion of the Altamont project, an additional 250 MMcf/d of Canadian gas could be transported on Kern River's base system since three of Altamont's shippers, Amoco, Chevron, and Union Pacific Fuels, hold that capacity in aggregate, on the Kern River base system.

The Kern River "expansion system", for which an application has been filed with the FERC, would increase Kern River's capacity by approximately 452 MMcf/d and allow it to provide open access transportation service to the expansion shippers. In an agreement of 20 July 1989, between Kern River and Altamont, certain exclusive rights to Kern River's expansion capacity were acquired by Altamont. Altamont and nine of its shippers subsequently entered into firm transportation service agreements with Kern River for an aggregate volume of approximately 452 MMcf/d[116]. In testimony,[117] Altamont stated that it expects Kern River's expansion capacity to be larger than the 452 MMcf/d applied for with the FERC. Two or three additional customers signed by Altamont since Kern River's FERC application are currently discussing expansion capacity with Kern River, requiring the total expansion capacity to be between 450 and 550 MMcf/d, according to Altamont. In the Friedenberg study prepared for Altamont,[118] a Kern River expansion capacity of 500 MMcf/d was projected. Altamont submits that all of its volumes should be able to move to California and to other markets[119] and that, although Rocky Mountain gas would initially be used to develop markets, Canadian gas would gradually replace Rocky Mountain gas on completion of the Altamont project. Altamont asserts that Kern River expansion is inevitable since Rocky Mountain natural gas reserves are to continually increase in the future. However, some of these reserves are deep while others are tight sands with very long lives of 30 to 50 years. Currently, the Rocky Mountain region is not an area where there is a large surplus of shut-in gas.[120] The Kern River base and expansion systems would be expected to handle the majority of Altamont's proposed 719 MMcf/d capacity, for which Canadian supply sources, where identified, are indicated in Appendix C.

6.3 PGT

Referring to its own project, which would require approximately 6.60 trillion cubic feet of gas over a 20-year period beginning 1 November 1993, PGT states that sufficient gas supplies are available in Canada.[121] Most of PGT's Expansion Project requirements would come from Alberta and approximately 10 per cent would come from British Columbia via Westcoast-Northwest Pipeline and Westcoast-NOVA interconnections. PGT projects that by the mid-1990's, Alberta still represents a major supply basin to satisfy California gas requirements, as shown in Figure 6-3.[122] For the longer-term, reliance is placed on frontier and unconventional gas sources such as coalbed methane and gas from tight sands, and considerable weight is given to a 1990-91 study by Armstrong, Calantone and Khan,[123] which concludes that, "with the recognition of continuing technological advances there will be adequate supplies of natural gas at a reasonable cost for expected Canadian demand, currently approved pipeline capacity, and this Expansion Project". In response to a request from the Board for an "assessment of whether there is sufficient gas available under Alberta's current gas removal policies to support either or both proposed projects over the 20-year period beginning 1 November 1993," PGT

replied that current Alberta gas removal policies, requiring reserves-in-place to support the full term of a removal permit, imposes extra costs on Industry.[124] PGT further suggests that "to permit Alberta producers the opportunity to compete effectively in today's market, the ERCB may be required to rely on the effective management of gas inventories by Alberta companies". PGT states that its shippers and suppliers represent some of Alberta's largest producers, with substantial supplies to support their commitments.

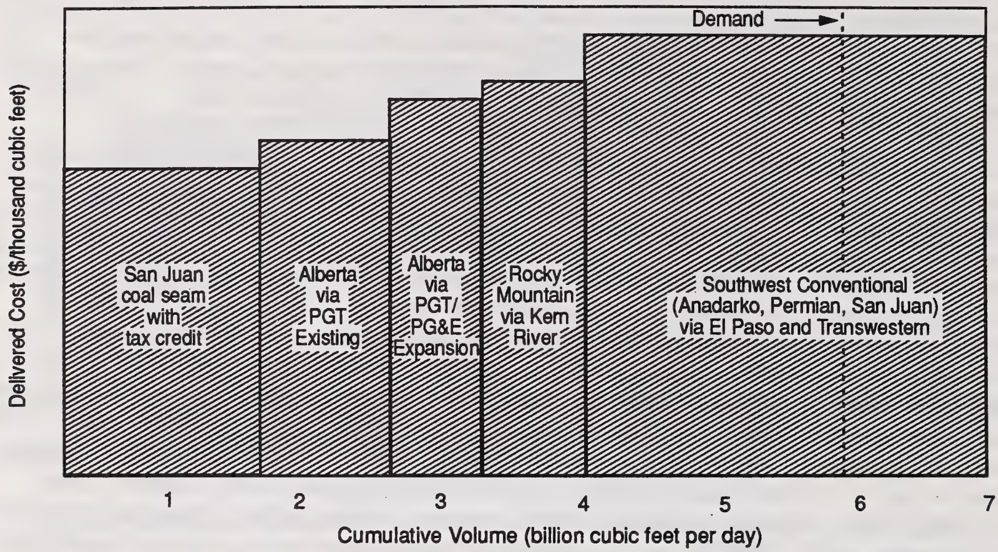

Figure 6-3 PGT View of Sequence of Supplies to California: Mid-1990s

In testimony, PGT reiterated its position that reserves will be developed to supply shippers' requirements over longer-terms equal to their 30-year transportation agreements.[125] This would, in PGT's view, be the result of allowing the market to operate while recognizing the likelihood "that natural gas is going to act like a commodity into the foreseeable future, and that technological improvement is going to continue to increase the size of the available reserves". PGT also stated, that as time proceeds, transportation tolls will be lower and netbacks to producers will be higher, providing incentives to find additional gas.

PGT did not initially file supply information on behalf of its shippers, stating that it did not have such information and that it had requested its shippers to provide the information to the Board. Due to the voluntary nature of the proceeding and the commercial sensitivities involved, a number of shippers did not respond to the Board's Call for Information. As a means of providing available information, PGT filed responses concerning shipper markets and supply previously submitted to the NEB by ANG.[126] The information shows that supply arrangements have been made for a substantial portion of the PGT Expansion Project's total requirements, and that negotiations are proceeding for the remainder. Expected supply sources for shippers on the PGT Expansion Project, where identified, are listed in Appendix D.

6.4 SHIPPERS' AND SUPPLIERS' VIEWS ON GAS SUPPLY

In general, the shippers and suppliers indicate their support of positions taken by both project sponsors, which essentially state that existing proven reserves are sufficient to meet the 20-year needs of **either** project, but which could, with future market development, become sufficient to supply **both** projects. Some parties express the view that the Board's requirement of 100 per cent proven reserves dedication is too restrictive, causing unnecessary hardship for suppliers who would otherwise obtain removal permits on the basis of both proven reserves and future reserves expected to result from exploration and development. Several shippers and suppliers present comprehensive evidence of their current and expected future supply positions and express confidence that all of their transportation and market commitments will be satisfied. Others express similar confidence in their ability to secure adequate gas supplies but state that negotiations concerning supply are on-going and that commercial sensitivities make it difficult to divulge complete information. Most suppliers and shippers, describing their supply procurement activities, indicate their intention to initially use shorter term contracts and removal permits to secure markets, and then to replace these with longer-term contracts and permits as gas marketing conditions change.

6.4.1 Amoco Canada Petroleum Company Ltd.

Amoco states that it "has reviewed and supports the conclusions of both Altamont and PGT that more than adequate supplies exist to support **either** the Altamont **or** the PGT project".[127] For its own needs as a shipper, Amoco stated that, as the largest producer of gas in Canada, it has numerous options available and that its intention is to utilize its supply pool and supplement any shortfalls with proven undeveloped reserves, exploration success, purchased or carried volumes and/or aggregator decontracting, as necessary.

6.4.2 AEC Oil and Gas Company

AEC outlines an alternative approach to supply concerns, stating that although it believes it is important to construct additional facilities from Canada to provide improved access to the California market, there is a strong possibility that pipeline capacity available to serve California will exceed available markets.[128] AEC states that it would be prudent, from the standpoint of western Canadian producers and California consumers, to encourage the full utilization of existing storage and the development of additional gas storage in California. The provision of peak day service through the flexible use of gas storage is, AEC submits, generally more cost-effective than building excess pipeline capacity.

6.4.3 The Joint Submission of:

AEC Oil and Gas Company,
Esso Resources Canada,
Southern California Edison Company and
Western Gas Marketing Limited

Addressing the Board's question respecting matters of gas supply sufficiency, assuming both projects proceed, the Joint Submission expresses the view that "the ERCB should do nothing to restrict parties with gas supply and market arrangements necessary to support removal permit approval from receiving such approval".[129] Stating that since Altamont is on a slower track than PGT, "Altamont may benefit from future policy changes which relax the Board's current reserve requirements," and "such a

change may also assist parties who choose to proceed, at least initially, with short-term approvals". The Joint Submission further submits that "the possibility of a future change in policy should in no way delay approval of any removal permit application pending before the Board with respect to the PGT project, that meets the Board's existing standards".

6.4.4 Paramount Resources Ltd. (Paramount)

Paramount addresses the matter of reserves and deliverability by stating that the Board should adopt removal permit procedures which reflect the dynamics of the current and future environment for selling gas in North America.[130] Paramount submits that continued use of the existing surplus determination procedure is too restrictive and counter to the longer-term interests of the Province of Alberta.

6.4.5 San Diego Gas & Electric Company

SDG&E notes, with regard to gas supply, that not all gas for the projects will be sourced in Alberta.[131] In its own case, approximately 38 per cent of its volumes will come from British Columbia. Also, SDG&E submits that the Board should deal with a possible shortage of permittable Alberta supplies by issuing removal permits, as they are applied for by producers, to the various projects. In this manner, according to SDG&E, the issue can be addressed while respecting the current, deregulated market-based environment. As to whether the Board's removal permit policies should be revised, SDG&E submits that although this is a possibility, it should be resolved in a different forum.

6.5 COMMENTS REGARDING GAS SUPPLY

As a means of presenting a general question regarding the adequacy of gas supplies over a reasonable period, beginning on estimated start-up dates for both projects, the Board presented its supply question in terms of Alberta's current gas removal policies and a 20-year period beginning 1 November 1993. The Board recognizes that although most of the gas supply is expected to be sourced in Alberta, a large portion will be sourced in British Columbia and some in Saskatchewan. The possibility of unconventional and frontier gas supplying longer-term requirements is also recognized. Although development of unconventional and frontier supplies may occur sooner than present market and supply conditions suggest, the Board has assumed that, for at least 20 years, conventional reserves produced in Alberta would provide the main supply for both projects. The Board expects, as do most respondents to the Call for Information, that additional reserves and productive capacity would be developed as needed to meet shippers' requirements. The Board also believes that future improvements in recovery technology will increase the amount of reserves available for market.

Table 6-1 of this report provides the Board's current estimate of Alberta "Gas Reserves Available for Inclusion in Permits". The calculations are based on year-end 1991 reserves and production estimates and also on remaining permit commitments at year-end 1991. As shown in Table 6-1, some $172 \times 10^9 m^3$ (6.10 Tcf) of gas remained committed to short-term permits. Although the percentage of actual gas removed under short-term permit commitments has steadily increased over the past several years, latest figures indicate that on average, only about 25 per cent of total authorized permit volumes are actually being shipped. While much of the unused permit volumes likely result from lack of transportation capacity, market constraints are also a factor in determining actual short-term permit usage. Notwithstanding the possibility that increased transportation capacity could result in higher actual permit use, the Board believes that substantial volumes currently shown to be required for short-term permits could find their way into new sales contracts and new removal permits. For this

reason, the Board does not consider the 201 x $10^9 m^3$ (7.13 Tcf), shown in Table 6-1 as Available for Permits, to be the threshold beyond which it would refuse to authorize further gas removals from Alberta.

*The Board's policy with respect to permit terms of greater duration than 2-years (long-term permits) is stated in ERCB Report 87-A, page 18, as follows: "**The maximum term for which the Board is prepared to grant a permit would normally be 15 years. However, the Board would be prepared, in special circumstances, to grant permits for periods of up to 25 years, if it is demonstrated that such a term would be in the Alberta public interest.**" The Board has on occasion received applications for permit terms longer than the 15 years for which it protects Alberta's own "core" market requirements. The policy is designed to create a framework for dealing with such applications, if they are in the Alberta public interest, and is not intended to impose a minimum term or to suggest terms of 15-years or longer. The Board notes that there are permits in place today with terms much less than 15-years, supplying contracts with terms longer than the removal permits. These permits were issued on the basis of proven reserves dedicated for total **permit** requirements, but with no consideration of total **contract** requirements. As stated also in ERCB Report 87-A, page 16, **"The Board believes that as a general objective, the gas removal policy should adequately protect the Alberta public interest, but should not be overly complex or interfere significantly with the business affairs of producers, shippers, and all buyers of Alberta gas."***

Table 6-1 Board Estimate of Gas Reserves Available For Inclusion in Permits as at 31 December 1991

	10^9 m^3 at 37.4 MJ/m^3	Tcf at 1000 Btu/ft^3
Reserves		
1. Total Remaining Established Reserves (as at year-end 1991)	1670	59.27
Less:		
2. One-half of Reserves Beyond Economic Reach and Deferred Reserves[r]	83	2.94
3. Total Available Reserves	1587	56.33
Requirements		
Alberta Requirements		
4. Core Market Requirements[s]	107	3.80
5. Contracted for Non-core Markets[b]	66	2.34
6. Permit-related Fuel and Shrinkage	110	3.90
Permit Requirements		
7. Remaining Permit Commitments (short-term 15.6%) (long-term 84.4%)	1103	39.15
8. Total Requirements	1386	49.19
Available		
9. Available for Permits	201	7.13

Although the Board requires 100 per cent proven reserves for the volumes retained in long-term removal permits, it does not consider the total volumes under contract. This allows producers some flexibility in meeting contractual commitments.

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[r] ERCB estimates that half of the gas in the BER and Deferred categories will become available over the next 20 years.

[s] For the sake of these estimates, 15 years of core market requirements and 5 years of non-core requirements were used.

7.0 REGULATORY ISSUES

7.1 SUMMARY OF THE STATUS OF REGULATORY AUTHORIZATION

7.1.1 Altamont/Kern River Project

Altamont Canada has applied to the NEB pursuant to Section 58 of the NEB Act for approval to construct a 300 metre section of pipeline which will cross the Canada-US border. Altamont advised the Board in its submission, that the NEB had ruled that the application would be dealt with in writing, and that the process had advanced to the point of information requests and responses. Altamont expected that it would receive NEB approval long before construction would need to begin. Subsequently, the NEB announced on 15 April 1992, that it intends to conduct a written procedure to determine whether the proposed pipeline of Altamont is part of a larger extraprovincial undertaking to be constructed from a point near Empress. Details of this procedure have yet to be announced. In a response to the NEB on 8 May 1992, Altamont expressed concern with the view that the Altamont Canada pipeline is part of a larger extraprovincial undertaking. Altamont also indicated that, to the extent that there is a jurisdictional question, the same issue must arise in respect of NOVA's activities in relation to all pipelines removing gas from the province, including the PGT Expansion Project.

Altamont filed with FERC for a conventional 7(c) certificate on 21 July 1989 for the authority to construct and operate the Altamont pipeline. Altamont filed a second application on 15 May 1990 to construct and operate its pipeline under an optional certificate. The FERC dismissed Altamont's earlier application on 28 June 1990 because Kern River had not yet filed an application to expand its system to transport Altamont's volumes. An appeal of this decision was heard before the US Court of Appeals for the District of Columbia Circuit on 18 February 1992, and a decision is pending. The FERC granted Altamont final certificate authority to construct and operate its project under the second application on 1 August 1991, and Altamont accepted its 'optional' certificate later that month.

Despite its outstanding appeal on FERC's dismissal of Altamont's Traditional 7(c) application before the US Court of Appeals, Altamont advised the Board that it had no plans to convert from a modified to a straight fixed variable rate design. The company preferred to accept a higher level of risk of underutilization in order to be allowed to receive a higher return on equity. Given that FERC's rules governing construction of gas pipelines are currently in a state of flux, Altamont did indicate, however, that it reserved the right to seek whatever additional authorization might be appropriate in the future to maintain the viability of its project.

Altamont also advised the Board that certain rate issues regarding the Altamont and PGT projects were left unresolved pending the issuance by FERC of a Final Construction Rule. FERC issued Order 555 on 20 September 1991 but stayed the effective date of the rule on 13 November 1991 until 30 days after publication in the Federal Register of a final order not subject to rehearing. Order 555, as issued, would eliminate optional certificate procedures and would instead place pipelines at risk if unable to meet the revised traditional certificate standards.

Pursuant to a 20 July 1989 agreement with Altamont, Kern River filed an application with FERC on 19 November 1991, to expand its system by about 452 MMcf/d by adding compression and pipeline facilities to provide open access transportation service for Altamont volumes. Kern River's application was for a Certificate of Public Convenience and Necessity under Section 7(c) of the Natural Gas Act. In the same application, Kern River also sought authority to operate both its base and expansion systems under a single conventional 7(c) certificate. This would supercede the optional certificate

previously issued to Kern River. Kern River advised the Board that it did not request that FERC change its rate design for its existing facilities, nor did it intend to seek such a change during the initial 15 year term of the existing system's transportation agreements.

Kern River's expansion application to FERC assumed that Mojave would concurrently expand its system by 200 MMcf/d; this was considered to be Kern River's "Primary Case". Kern River also presented to FERC an "Alternative Case" in the event that Mojave decided not to proceed with an expansion of its system. On 10 January 1992, Mojave advised FERC that it intended to apply for its expansion by 28 February 1992. The FERC notified Kern River, however, that it would not complete an analysis of the Primary Case without information on Mojave's proposed expansion. Therefore, the FERC rejected Kern River's Primary Case, without prejudice to Kern River refiling it, once Mojave files its companion application.[132] Mojave subsequently filed an application with the FERC on 28 February 1992 for an optional certificate to expand its system by up to 200 MMcf/d to accommodate the Kern River Expansion.

In its submission, Altamont advised that some shippers had already applied for removal permits but noted that the Board had specified in its Call for Information that it would not make any decisions on such applications until this proceeding is completed. Altamont expects that there will be ample time thereafter to proceed with removal applications to meet a November 1993 in-service date. Altamont noted that one of the suppliers to a shipper on its project had applied to the Board for a removal permit and that other shippers were expected to apply later in 1992. Altamont also advised that no Altamont shippers had yet applied to the NEB for export licences but that applications were expected during the third quarter of 1992.

7.1.2 PGT View on Altamont Regulatory Status

PGT has pointed out that several issues in Altamont's optional certificate, including the appropriate target load factor and Altamont's 'at-risk' conditions, have been held in abeyance by the FERC. Although these issues remain outstanding, Altamont claims that they do not represent an impediment to obtaining financing and will not delay the project. Altamont also added that even if a target load factor of 90 per cent were adopted by the FERC, the return on equity that Altamont would be allowed to collect would also probably be reduced, thus minimizing the rate impact on shippers.[133]

PGT argues that the Altamont late start in analysing environmental impacts puts its commissioning date at risk. While Altamont has identified some 551 cultural resource sites and claims to be on schedule to receive leave to construct from the FERC in April 1993, PGT doubts that Altamont has completed the necessary cultural and biological work necessary to satisfy the significant requirements that the permitting agencies will place on its project. PGT testified that its cultural and biological work on an existing right-of-way commenced in 1988 and is still underway.

7.1.3 Comments on Status of Altamont Regulatory Authorization

With regard to the outstanding "at-risk" conditions related to Altamont's optional certificate, clearly a lower target load factor for rate design that is not offset by a lower return on equity would serve to increase Altamont's rates and, therefore, diminish the project's attractiveness to Alberta shippers.

Despite the argument by Altamont that the terrain through which its pipeline is proposed appears to suffer less environmental impediment, environmental risks are possible.

7.1.4 PGT Expansion Project

In its submission, PGT advised that the ANG and Foothills portions of its project are awaiting disposition of applications for facilities filed with their respective regulatory authorities, the NEB and the Northern Pipeline Agency, on 31 May 1990. On 21 May 1992, the NEB issued Order XG-16-92 which found ANG's applied-for facilities to be in the public interest.

In the US, although FERC granted PGT a Certificate of Public Convenience and Necessity on 7 August 1991, PGT was banned from commencing construction until the FERC was satisfied that the PGT Expansion Project shippers had non-discriminatory access to the California market. On 24 October 1991, the FERC issued an "Order on Report and Modifying Prior Order" which rescinded its earlier construction ban related to the lifting of PGT and PG&E's perceived illegal tie-in arrangement, and instead reduced PGT's rate of return on equity to 10.13 per cent, pending a resolution of the situation. While the PGT certificate is subject to a rehearing, the FERC has declined to set a date to review these orders on rehearing until the CPUC has issued a decision on its review of the crossover ban at Malin and incremental rates for northern California shippers on the expansion project.

PGT considers that the reduction in its return on equity and the issues tolled in its certificate will not affect its ability to raise capital and would not, therefore, delay construction. The lower return on equity should not affect the decisions of issuers of debt capital and, according to PGT, the fact that some of the orders in the certificate are tolled is typical of the regulatory process in the US. PGT notes that due-process requirements and the greater tendency toward litigation often prolong regulatory procedures past the commissioning date of certified facilities. As a result, it is commonplace for regulatory agencies to approve milepost-to-milepost construction before the end of the rehearing and appeal process. As PGT contends that the issues tolled would not affect financeability, it has elected to commence construction despite some outstanding rehearings and appeals.[134]

With regard to the California portion of the expansion project, the CPUC initially granted a Certificate of Public Convenience and Necessity on 27 December 1990. This certificate was modified several times culminating with a decision on 19 June 1991, that denied expansion shippers access to PG&E's existing facilities (see Section 4.5.2). The CPUC subsequently initiated a proceeding in November 1991 to respond to the alleged rate discrimination identified by FERC, in its approval of the PGT Expansion Project, and to the petition for rehearing by a group of expansion shippers intending to ship to PG&E's northern California service territory. The issue that was addressed, with a decision to be announced shortly, was the allocation of costs between shippers on the existing PG&E system and the PG&E portion of the expansion project. PGT asserts that these ongoing proceedings are rate related and, thus, are not likely to affect the construction schedule.[135]

In its submission, PGT advised the Board that applications for new or amended removal permits had been filed by five expansion shippers, accounting for about a quarter of the expansion volume. Further, export licence applications had been filed by, or on behalf of, four utility end-users with the NEB representing over a third of the expansion volume. Finally, two long-term import applications had been filed with the US DOE, along with a number of short-term import applications. It was expected that by the end of the first quarter of 1992, applications for removal permits and export licences would have been filed by about 15 shippers, representing about 57 per cent of total expansion volumes.[136]

7.1.5 Altamont View on PGT Regulatory Status

Although PGT sponsors claim that they are confident of attaining their November 1993 in-service date, Altamont contends that a number of regulatory uncertainties exist which may delay the expansion project. Altamont purports that it is highly unlikely that the CPUC will approve PG&E's partial rolled-in toll proposal and, as a result, shippers who have not yet signed contracts with PG&E will decline to do so. Moreover, even some of the shippers who have already signed would be able to renegotiate their contracts in this event.

Altamont has also identified the current CPUC proceeding which is examining an expansion to PG&E's Line 300, as a related regulatory issue. As an expansion to Line 300 would permit additional southwest gas to supply northern California, Altamont claims that the pendency of the proceeding raises substantial questions as to whether the PGT Expansion Project is needed to serve northern California.

Altamont also claims that significant uncertainty exists with respect to an appeal regarding Altamont's request for a comparative hearing. On 18 February 1992, the US Court of Appeals for the District of Columbia Circuit heard oral argument regarding Altamont's claim that the FERC improperly refused to hold a comparative hearing regarding the Altamont and PGT projects. If Altamont prevails, then it suggests that the Court will likely remand the case to the FERC for a comparative hearing, which could result in the recision of PGT's certificate.[137]

7.1.6 Comments on Status of PGT Regulatory Authorization

The decision of a number of shippers to abandon the expansion project, if the CPUC affirms the crossover ban and denies a partial roll-in, could affect the project's viability. However, a number of alternatives are open to the CPUC; assuming that a decision will be made that would be rejected outright by shippers is premature. The Line 300 Proceeding currently before the CPUC, should not impose further regulatory impediments to the PGT Expansion Project as the CPUC denied several related motions on 31 March 1992, to stay PG&E's certificate for expansion of facilities.

7.2 THE ISSUE OF CPUC CONTROL

Evidence was presented, by both Altamont and PGT, regarding the extent of CPUC control over their respective projects. PGT recognizes that, as the CPUC has jurisdiction over all gas distribution companies operating within the state's borders, its gas volumes delivered in PG&E's service area are subject to the rate and service regulations of the CPUC. Altamont, however, notes that its project proposes to construct interstate facilities that would be subject only to FERC jurisdiction. Kern River's status as an interstate pipeline in California presents the possibility of serving customers directly, offering in Altamont's opinion, an added benefit since such volumes would not be subject to CPUC's jurisdiction.

PGT contends that any volumes delivered by Altamont into any of the regulated gas utilities will be subject to the same CPUC regulation. PGT also points out that the largest Altamont shipper, PIC, has recognized that its contracts with end-users in California are conditional upon the approval of the CPUC, which regulates SoCalGas. Altamont responds that the CPUC's jurisdiction over SoCalGas is significantly less of a disadvantage to Alberta than the CPUC's control over PG&E. If the CPUC, through the exercise of its regulatory authority, makes doing business with SoCalGas too expensive, by-pass is always an option. In addition, Altamont contends that SoCal Edison and SDG&E, which are

shippers on the PGT Expansion Project, are both utilities in the State of California and, like PIC, would be subject to CPUC policy on gas procurement. While PGT concedes that these two utility shippers will indeed be subject to CPUC regulation, it argues that the review process should be somewhat different for electrical utilities seeking to secure their non-core portfolios.[138]

PGT also notes that, according to the terms of an agreement among Kern River, Mojave, and SoCalGas, the intrastate facilities of Kern River and Mojave would revert to CPUC jurisdiction by 2012. However, Kern River points out that the agreement among itself, Mojave, and SoCalGas to transfer the intrastate facilities of Kern River and Mojave to CPUC jurisdiction after 20 years, is far from automatic. The agreement states that the transfer is subject to certain regulatory action by the CPUC in regard to accepting jurisdiction and honouring the contractual rights of the shippers on the California facilities. The FERC also stated that jurisdiction over facilities is not an issue the parties could decide among themselves; rather, the FERC's jurisdiction over facilities is a matter of Federal law.[139]

7.2.1 Comments on CPUC Control

The significance of the regulatory jurisdiction under which each of the proposals falls must be judged by producers. The FERC is a federal regulator with objectives relevant to efficiency of service. The CPUC is likely to put greater emphasis on the welfare of California consumers and, if so, could make decisions adverse to the interests of producers. There are, however, risks associated with the decisions of both of these agencies. Although Altamont is primarily under the jurisdiction of the FERC, some of its customers could fall under the CPUC's jurisdiction and associated influence.

8.0 DISCUSSION OF SELECTED ISSUES

8.1 NEED FOR ADDITIONAL INTERSTATE PIPELINE CAPACITY EXPANSION INTO CALIFORNIA

The proponents are in close agreement on the growth of California's need to import gas. The differences in the proponents' market perception lies in the distribution of demand growth between northern and southern California. PGT's evidence suggests that while mutual-assistance agreements exist between northern and southern California gas utilities, there is not enough flexibility in existing pipelines to enable gas to be moved at will between northern and southern California. For this reason, the need arises to identify market opportunities and the requirement of respective interstate pipeline capacity to supply each of northern and southern California.[140]

8.1.1 Capacity Required by Northern California

PGT's expansion project was originally intended to meet the needs of southern California utilities. As additional markets were identified, facilities applications were amended to include additional volumes destined to northern California. The current 250/505 MMcf/d northern versus southern California split, in PGT's submission to this Board,[141] *reflects shippers' expressions of intent gathered during the summer of 1991. PGT notes that executed contracts between shippers and PGT specify a total southern California delivery volume of 332 MMcf/d, as compared to approximately 222 MMcf/d to northern California.*[142] *The final split in contract delivery volume is not yet clear, pending the conclusion of contract negotiations between PG&E and the prospective shippers. However, PGT estimates that northern California deliveries could total 423 MMcf/d.*

The shift in destination toward northern California, however, would not warrant significantly different facilities from those currently proposed.[143] *The current design allows flexibility to move volumes of gas directly or by displacement, to end-users anywhere in southern or northern California. PGT expects a significant portion of northern California deliveries to satisfy markets south of Panoche Junction into the San Joaquin and Salinas Valleys and the southern part of the San Francisco Bay Area, all of which are in the southerly portions of northern California.*

PGT projects that northern California gas imports will increase from 2206 MMcf/d in 1992 to 2982 MMcf/d by the year 2010.[144] *Given that current pipeline capacity into northern California is 2160 MMcf/d, the implied capacity used in 1992 is 102 per cent, projected to increase to 138 per cent by the year 2010, unless interstate capacity is expanded. Under Altamont's projection of interstate shipments,*[145] *use of existing capacity is 90 per cent in 1992, increasing to a hypothetical 122 per cent by the year 2010. These results are summarized in Table 8-1.*

For the year 1992, use of existing capacity is then likely to be somewhere between 90 and 102 per cent (full use) without additional storage capability. (This compares to actual utilization of PGT in 1989 at around 99.5 per cent).[o] *This fact does not necessarily mean that core market demand could not be met at peak days. Curtailing interruptible non-core customers could be one method of meeting peak core demand. PGT claims current capacity is not enough to meet peak demand, whereas Altamont believes firm transportation for peaking needs in 1992 can be met by curtailing interruptible customers or through additional storage capacity.*

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o *1991 Fuels Report Working Paper: Natural Gas Market Outlook, December 1991, B-13.*

With an additional firm capacity of 250 MMcfld into northern California, future average-day use as a percentage of capacity under Altamont and PGT projections of gas imports into the region, is shown in Table 8-2.

Table 8-1 Projected Utilization of Current Take-Away Capacity into Northern California*

	Forecast of Interstate Shipments (MMcf/d)		Average-Day Demand as Per cent of Existing Capacity	
	Altamont	PGT	Altamont	PGT
1992	1931	2206	90	102
1995	1875	2247	87	104
2000	2003	2538	93	117
2005	2398	2752	111	127
2010	2630	2982	122	138

* Does not include 340 MMcf/d of El Paso and Transwestern capacity additions where no take-away capability is currently available.

Table 8-2 Average Day Requirement as Per Cent of Capacity Utilization as a Result of 250 MMcf/d PGT Expansion into Northern California

	Under Altamont Projection of Interstate Shipments	Under PGT Projection of Interstate Shipments
1995	78	93
2000	83	105
2005	99	114
2010	109	124

Obviously, the larger the expanded pipeline capacity into northern California, the lower will be the use of interstate pipeline capacity. For a 420 MMcfld expansion, the implied utilization rate for 1995 ranges from 73 per cent, under Altamont's forecast of gas requirements, to 87 per cent under PGT's.

A capacity use factor of less than 100 per cent as a result of the expansion implies that some sources of supply will be displaced at off-peak times. It also implies increased competition among the different supply basins to satisfy requirements at off-peak times, which could lead to downward pressure on the price of gas. The extent to which pipelines carrying Alberta gas will be fully utilized depends, particularly at off-peak times, on burner-tip price competitiveness and the willingness of Alberta producers to accept lower netbacks in return for a larger market share, as well as the contractual commitments in place. Given a rate design that allows cost recovery through demand charges, there will be a strong incentive for shippers to use the expansion at the highest possible load factor. This could leave existing Alberta sales into northern California and sales of US southwest supplies vulnerable to reduced prices, if market share is to be maintained. Alternatives to new capacity to handle peak loads include greater reliance on interruptible supplies and developing more storage capacity. These options might address the needs of consumers more efficiently than new pipeline capacity in the immediate future, as was noted by AEC.[146]

8.1.2 Capacity Required by Southern California

Altamont and PGT agree that excess interstate capacity is available to supply the southern California market. PGT's analysis suggests that only in 1997 does southern California start requiring additional capacity.[147] Moreover, with the proposed capacity of the PGT expansion in place, southern California would not experience a capacity deficiency until beyond the year 2005. Altamont's analysis of capacity requirements is not provided on an annual basis; however, at the oral examination, Altamont indicated that roughly 400 MMcf/d of its full subscription, of which 350 MMcf/d is in southern California, is to be contracted for on a firm basis.[148] Altamont stated this is not an incremental market, but rather a displacement market. There is no immediate need for incremental gas into southern California. Altamont says it would take about 7 years to fill either of the proposed facilities, assuming that every cubic foot of incremental market demand is allocated to these facilities.

The evidence provided by both proponents suggests that, at least over the next 5 years, no additional capacity is required to supply southern California and that either project, if completed, would result in some displacement of current gas supplies serving southern California.

8.2 DIFFERENCES IN PROPOSED MARKETS TO BE SERVED

The PGT Expansion Project is to serve customers in the Pacific Northwest and California. The Altamont/Kern River Project offers Alberta producers access to markets in southern California and to alternate markets along the Kern River route in Utah, Nevada, and downstream of the CIG system. In addition, Altamont claims that markets east of Colorado, particularly the Midwest, can be accessed on an interruptible basis.

According to PGT, the Pacific Northwest region already suffers from a deficit in peak day capacity and is, therefore, particularly ready for interstate pipeline expansion. Markets to be served through proposed PGT facilities constitute local distribution companies' system requirements and some direct sales to end-use industrial customers. Marketing arrangements for some of the proposed capacity to this region have already been finalized. With a view to transportation rates, the Pacific Northwest is more accessible by BC gas and Alberta gas off the PGT system, than by Alberta gas off Altamont. Therefore, PGT provides the least-cost access to the Pacific Northwest, where Alberta and BC producers would compete for market share.

Northern California has been the primary target market for gas delivered through the existing PGT system. While final contract delivery volumes on the expansion have not yet been determined, the fact that pipeline capacity seems tighter than that in southern California could suggest greater demand for incremental supplies. Altamont suggests that its system will be able to serve markets in northern California through expansion on the PG&E system. Altamont identified PG&E's Line 300, as a possible route to increase US domestic gas deliveries into California. This is being examined at a current CPUC proceeding but that is not likely to delay PGT's expansion project, as the CPUC denied several related motions to stay PG&E's certificate for expansion of facilities on 31 March 1992. Even if such a supply route proved beneficial for California, the timeframe required for it to materialize could be several years after the currently proposed expansions are to come on-stream. It is unlikely that Altamont would be able to serve northern California gas requirements beyond the southern portion of PG&E's service territory by November 1993. However, this market, as suggested by Altamont, could be accessed to some extent by displacement of US southwest gas, via interruptible transportation, or through direct interconnection between the Kern River system and individual end-users.

Currently, the total volume proposed for delivery to southern California on the PGT expansion is 332 MMcf/d. Most of this volume is under end-use market contracts with SDG&E, SoCal Edison and the cities of Burbank, Glendale and Pasadena. PG&E has executed an Interconnection Agreement with SoCalGas to physically deliver this volume.[149] *Evidence suggests that once the rate issue on the PG&E portion of the system is resolved by the CPUC, there will be incentive for additional sales in PG&E's service area, rendering the Pacific Northwest and northern California as the principal markets for the expansion.*

Altamont's evidence is that approximately 350 MMcf/d of its total capacity is committed to end-use markets in southern California, however, only a small portion of that is subject to contractual arrangements. The PIC subscription on Altamont of 200 MMcf/d, is the only volume prospectively destined to a local distribution company. Amoco argues that Altamont provides the opportunity to supply the growing EOR and power generation market in southern California through by-pass of the utilities system and direct interconnection to Kern River. The cost of this interconnection could be significantly lower than the utilities' intrastate rate. Amoco points out that approximately 90 per cent of its contracted volume to California on the Kern River base system is directly connected to California customers, at transportation costs in the order of 5 to 10¢/Mcf (US). This suggests the possibility that Altamont's potential market in southern California is distinct and may not be directly comparable to that of PGT. However, if by-pass volumes become significant, the utilities may have to increase the cost of services provided to remaining customers to meet their revenue requirement. Depending on the competitive environment, this could have implication for sales, prices and netbacks to Alberta.

Altamont believes access to the pipeline hub at Opal would provide the opportunity to serve nearly any market in North America, if primary markets do not take previously contracted gas. Altamont believes its project offers Alberta producers access to long-term markets in Colorado, Utah and Nevada, in addition to markets in the Midwest that can initially be accessed on an interruptible basis. Notwithstanding Amoco's submission that it has proposals (for a total of 200 MMcf/d), with prospective customers in and upstream of California, in Utah and in Nevada, the evidence presented did not resolve the question of the economic feasibility of selling Alberta gas in a market that is traditionally served by Rocky Mountain supplies. Moreover, the evidence leaves open the question of whether markets east of Colorado, particularly the Midwest, could be economically served by Alberta gas off the Altamont system. To the extent that such markets, some of which may be new opportunities for Alberta gas, could be accessed at some point in time, they do represent distinct and separate markets from those that PGT is proposing to serve.

Although the markets intended to be served by PGT and Altamont are somewhat separate and distinct, some portion of each proponent's market could be served, by the competing proposal, through displacement. If both pipelines go ahead, the result could be excess supply in the overall market for a considerable period of time — with associated implications for prices and netbacks.

8.3 COMPARATIVE PRODUCER NETBACKS

As mentioned earlier, the Board notes that the different conclusions reached in the PGT and Altamont netback analyses result from different assumptions favouring each proponent's own project. Recognizing the complexity of the analysis required, the Board is reluctant to comment on the set of assumptions underlying each of the submissions, yet is not entirely comfortable with either. As an example, the WMR analysis assumed no price impact on existing Alberta sales into California. Although, at the oral examination, Dr. Mansell acknowledged that such an impact could occur, he

confirmed that his study did not quantify that effect.[150] *Altamont considered the effect when evaluating PGT but excluded it when assessing its own project.*

The Board believes that, regardless of the point at which expanded capacity enters the market under competitive circumstances, there will be an impact on the price of existing sales of gas in California at least over the short-term. The extent and duration of this impact is difficult to quantify.

8.4 PROJECT COST EFFICIENCY

Both projects attempted to illustrate their superiority in terms of the impact on the Alberta public interest by way of a detailed netback analysis. Given the uncertainty of the results because of market price assumptions, this section focuses on which project transports its gas to market in the most cost-efficient manner, assuming the cost of delivering the gas to market as submitted by proponents. To the extent that each project can access gas markets with similar burner-tip prices, the pipeline with the lower unit transportation costs will yield the higher netback. As these projects are designed to serve only one common market (i.e. southern California), it would be desirable to isolate the associated costs for both projects to serve only this market. A lack of evidence in this regard, however, makes such analysis not possible.

The fact that the PGT Expansion Project's ex-Alberta capital costs are almost double those of Altamont/Kern River, may lead some observers to conclude that the latter project is the more cost efficient. The Board does not consider a comparison of these capital costs as filed to be a valid indicator of the projects' relative efficiencies. Not only is the PGT Expansion Project slightly larger in scale, but the Altamont/Kern River Project cost estimate does not include all the expenditures required to transport Alberta gas to market as it excludes the cost of the base Kern River system that will be used by Alberta shippers. The fact that this system could have a maximum of 250 MMcf/d[P] *of Canadian gas flowing to California with shippers paying the appropriate demand charges, suggests that some of the base Kern River cost should be taken into account. Indeed, these charges are reflected in the filed transportation rates of the Altamont/Kern River Project. In addition, the fact that the Altamont/Kern River project incurs higher intra-Alberta capital costs, indicates that the differential in cost is not as wide as it initially appears to be. When all these factors are taken into account, the unit capital costs of each project (ie. capital cost per MMcf of daily capacity) may not be significantly different.*

The Board has considered two measures of project cost efficiency: transportation rates to Kern County and unit revenue requirements. These two alternatives are considered in more detail in the sections that follow.

P *Of Altamont's shippers, Amoco Energy Trading Corporation currently holds 50 MMcf/d of capacity on the base Kern River System while Chevron and Union Pacific Fuels each hold 100 MMcf/d.*

8.4.1 Transportation Rates

In Section 4.5.3, the Board considers the ex-Alberta transportation rates as filed by the two projects and concludes that PGT would appear to hold an advantage; its transportation cost of serving the southern California market is marginally lower than Altamont's, when these rates are compared over time. Table 8-3 summarizes the results of the Board's analysis.

Table 8-3 Levelized Unit Rates (1991 Canadian ¢/GJ)

	5 Per Cent Discount Rate	10 Per Cent Discount Rate
Altamont/Kern River Project (@ 100% Capacity Utilization)	60.90	66.14
PGT Expansion Project (@ 100% Capacity Utilization)	56.14	61.62
Altamont/Kern River Project (@ 75% Capacity Utilization)	74.90	81.28
PGT Expansion Project (@ 75% Capacity Utilization)	71.48	78.47
Altamont/Kern River Project (@ 50% Capacity Utilization)	102.92	111.57
PGT Expansion Project (@ 50% Capacity Utilization)	102.17	112.17

Because of differences in rate design, the PGT rates are more sensitive to variations in use of capacity, since proportionately more of this project's cost of service is allocated to the demand component. Table 8-3 shows, however, that at a capacity utilization of 75 per cent, the PGT project retains its rate advantage. At 50 per cent capacity use, this advantage tends to disappear.

Many uncertainties arise regarding the rates as filed by both parties. Altamont says that, as a brand new pipeline with no opportunity to reallocate costs to an existing system, it stands less risk that its rates have been underestimated. From a regulatory standpoint, however, some uncertainty does exist. FERC's impending construction rule, Order 555, may reduce the load factor that Altamont has used to calculate its rates, and FERC's Order 636 may eliminate Altamont's modified fixed variable rate design in favour of a straight fixed variable design. Both rules could affect the rates incurred by shippers on the Altamont/Kern River project.

In addition to regulatory uncertainty surrounding the Altamont project, if Altamont has significantly underestimated its capital costs to the extent suggested by PGT, then its actual rates would certainly be higher than filed. From an engineering standpoint, the Altamont project is not as well defined as the PGT proposal and, therefore, more risk should be attached to Altamont in this regard.[q]

Altamont has identified a number of rate risks associated with the PGT project, some of which can be attributed to regulatory uncertainty regarding rate design. The allocation of operating and maintenance costs, and administrative and general costs, on a pro-rata basis between the existing and proposed PGT-PG&E facilities would increase rates faced by the expansion shippers. For this to occur, specific regulatory action would need to be taken by either the CPUC or FERC. A major

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q *While PGT costs have been guaranteed by Bechtel, no such arrangement exists for the Altamont project.*

reason why Altamont's transportation rates as filed are higher than PGT's is the fact that, included in Altamont's rates, are considerably higher fixed operation & maintenance plus administrative & general costs than those allocated to the PGT expansion.

Regulatory decisions would also be required for the imposition of mileage-based rates on PG&E or a take-or-pay surcharge to be levied on expansion shippers to cover the cost of any buy-out contracts with existing A&S producers.

There are two additional significant risks to PGT-PG&E rates as filed. PGT has initially accepted the risk that certain interruptible volumes, available as a result of the increased power output of gas turbine compressor stations during the winter months, will be transported. If these interruptible volumes do not materialize, however, PGT could attempt in future rate cases to recover these revenues from other volumes, thereby increasing firm shippers' rates. In addition, it is unlikely that PGT rates will decline annually in nominal terms, as it assumes in its response to the Call for Information. The length of time required to complete rate cases would suggest that, in nominal terms, the PGT rate will decline in a stepwise fashion over time. Longer intervals between rate changes would increasingly reduce any PGT rate advantage.

8.4.2 Unit Revenue Requirement

As an alternative to looking at the transportation rates, the Board has used the annual revenue requirement and each pipeline's maximum throughput to calculate a unit revenue that would satisfy both pipelines' cost-of-service requirement as filed.[r] *The advantage of this approach is to lessen the impact of variations in rate design and focus on unit costs. Once the annual unit revenue requirement for each project is determined, a levelized unit revenue requirement can be calculated to compare the cost efficiency of the projects over time. To further reduce the impact of rate design, both projects' revenue requirements are also calculated with the same return on equity of 12.5 per cent. Table 8-4 summarizes the results.*

Table 8-4 Levelized Unit Revenue Requirement (1991 Canadian ¢/GJ)

	5 Per Cent Discount Rate	10 Per Cent Discount Rate
Altamont/Kern River Project (@ 14.25% return on equity)	57.9	62.8
Altamont/Kern River Project (@ 12.5% return on equity)	57.2	62.1
PGT Expansion Project (@ 12.5% return on equity)	53.3	58.5

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r *As was considered in Section 4.5.3, the costs of expanding ANG and Kern River are rolled-in while PGT, PG&E and Altamont are incremental. The cost-of-service requirements are taken from Altamont's 14 April submission, while PGT costs are from the appendices in its final argument.*

The analysis suggests the PGT Expansion Project is more cost-efficient to the extent that this project has the lower levelized unit revenue requirement. Since it also incurs lower capital expenditure on NOVA, the total efficiency advantage is increased. These results should not be taken too literally, as some uncertainty surrounds the evidence supplied by each applicant. To the extent that PGT has underallocated costs from its existing system or that Altamont has underestimated the capital costs of its project, the results could be quite different.

*8.4.3 **Comments on Project Cost Efficiency***

Both projects' evidence as filed, used to examine project efficiency, results in analysis suggesting that the PGT Expansion Project has a slight advantage. At the discount rates used, both the PGT Expansion Project's transportation rate to Kern County and its unit revenue requirement range from 92 to 95 per cent of those of the Altamont/Kern River Project's, assuming pipeline capacity use of 75 to 100 per cent. However, this advantage declines will lower load factors and disappears at about 50 per cent capacity utilization. Both proponents have expressed concern with each other's rate assumptions. Altamont is particularly concerned that PGT has underallocated costs from its existing system to the expansion project. To the extent these concerns are realized, PGT's efficiency advantage could be reduced or eliminated. On the other hand, PGT doubts the validity of Altamont's cost estimates. If these costs have indeed been underestimated, the efficiency advantage of the PGT Expansion Project will be increased.

*8.5 **IMPACT ON THE PRODUCING INDUSTRY INTERESTS***

Two aspects of the proposals to increase capacity to California should be weighed by producers. The first is increased competition and its impact on the netback price to the producers; the second is additional access to the export market, with its positive impact of reducing excess supply in the intra-Alberta market.

Having additional pipeline capacity to serve regions where excess capacity already exists may cause a negative impact. Even if one pipeline is built, it will initially be serving a displacement market in southern California. Lower capacity use will translate into higher per unit transportation costs to both intra and ex-Alberta markets.

Excess capacity in the California market will also lead to lower market prices. A second new pipeline will be serving a displacement market, some of this displaceable gas being Canadian sourced. To the extent that US production would have to be driven eastward, prices at the burner tip in California must fall sufficiently that netbacks to southwestern US producers are lower than those of available alternative markets in the Midwest and the Northeast. The combined effect of higher unit transportation cost, as a result of lower use of capacity and lower market prices, would lead to reduced netbacks until the new pipeline facilities are fully utilized by the market.

As to the impact on the intra-Alberta supply surplus, additional access to any export market will reduce the surplus that now competes for the limited intra-Alberta market and therefore may allow an increase in Alberta spot prices.

The net effect on netbacks to producers is difficult to quantify but is likely to be more adverse to the interests of the producing industry if the two pipelines are commissioned in the near future.

END NOTES:

1. Altamont submission, 30 December 1991, Appendix 5.
2. Altamont submission, 30 December 1991, Appendix 5, page 12.
3. Transcript, page 795.
4. Altamont submission, 30 December 1991, Appendix 5, page 13.
5. Transcript, page 668.
6. Transcript, page 804.
7. PGT submission, 31 January 1992, pages 21-24.
8. PGT submission, 30 December 1991, page 22.
9. PGT submission, 30 December 1991, pages 51-52.
10. PGT submission, 30 December 1991, page 34.
11. PGT submission, 30 December 1991, Table 1-13, page 64.
12. Altamont submission, 31 January 1992, pages 33-35.
13. Transcript, page 785.
14. Altamont submission, 14 February 1992, Table 107A in response to PGT's Request 107.
15. Altamont submission, 14 February 1992, Table 9A in response to ERCB Request 9.
16. Transcript, page 783.
17. Transcript, page 783.
18. Transcript, page 784.
19. PGT submission, 30 December 1991, Tables 1-7 and 1-8, pages 51-52.
20. PGT submission, 30 December 1991, Tables 1-8, 1-10 and 1-12.
21. PGT submission, 30 December 1991, Tables 1-8, 1-10 and 1-12.
22. Transcript, page 509.
23. PGT submission, 6 April 1992, Attachment B (Undertakings from Dr. A. Safir at Transcript, page 482).

24. PGT submission, 30 December 1991, pages 39-42.

25. Altamont facsimile to ERCB, 14 May 1992.

26. PGT submission, 6 April 1992, page 29.

27. PGT submission, 6 April 1992, page 24.

28. Transcript, page 756.

29. Transcript, page 446.

30. PGT submission, 14 February 1992, in response to ERCB Request 3.

31. Transcript, pages 442-445.

32. Transcript, pages 796-804.

33. Transcript, pages 71-72.

34. Transcript, page 84.

35. Transcript, pages 74-75.

36. Transcript, pages 84-85.

37. Transcript, pages 82-83.

38. Transcript, page 20.

39. Transcript, page 767.

40. Altamont submission, 30 December 1991, Appendix 4, page 3.

41. Altamont submission, 14 February 1992, Section 1.

42. Kern River submission, 14 February 1992, page 4.

43. PGT submission, 30 December 1991, page 82.

44. PGT submission, 30 December 1991, page 109.

45. PGT submission, 30 December 1991, page 110.

46. PGT submission, 31 January 1992, pages 14-18.

47. PGT submission, 31 January 1992, pages 17-18.

48. Kern River submission, 14 February 1992, page 5.

49. PGT submission, 31 January 1992, Tab 3.

50. Altamont submission, 14 February 1992, pages 5-7.

51. Transcript, pages 89-116.

52. Altamont submission, 31 January 1992, pages 10-11.

53. PGT submission, 31 January 1992, pages 12-13.

54. Transcript, pages 87-89.

55. Transcript, pages 766-767.

56. Altamont submission, 14 April 1992.

57. Transcript, page 751.

58. PGT submission, 6 April 1992, Table 2-9N.

59. Transcript, page 748.

60. Kern River submission, 14 February 1992, page 2.

61. Transcript, page 267.

62. Transcript, page 294.

63. Altamont submission, 14 April 1992.

64. Altamont submission, 14 February 1992, Appendix 7, page 55.

65. Transcript, page 454.

66. PGT submission, 6 April 1992, Attachment.

67. Transcript, page 741.

68. PGT submission, 6 April 1992, Table 2-7ND.

69. Altamont submission, 30 December 1991, Appendix 9, Table 2.

70. Transcript, page 268.

71. A Comparison of Industry Netbacks from the Altamont and PGT Expansion Projects, Brent Friedenberg Associates Ltd., 12 March 1992, pages 16-18.

72. Friedenberg, pages 7-12.

73. Friedenberg, page 8.

74. Friedenberg, pages 17-20.

75. Friedenberg, page 20 and Transcripts, page 720 and pages 822-828.

76. Friedenberg, Appendix A, page 28.

77. Friedenberg, pages 13-14 and Transcripts, pages 832-839.

78. Friedenberg, page 22.

79. Transcript, pages 694-696.

80. Transcript, pages 701-702.

81. Transcript, page 707.

82. Transcript, pages 348 and 356, pages 718-720.

83. Transcript, pages 713-715.

84. A Comparison of the Netbacks and Economic Impacts Associated with the PGT Expansion and Altamont Projects, Wright Mansell Research Ltd., 31 January 1992, pages 2-6.

85. PGT submission, 30 December 1991, page 120.

86. Wright Mansell, page 21, Table 2.2.

87. Wright Mansell, page 20, Transcript, pages 387 and 474-475.

88. Wright Mansell, page 18, Transcript, page 367.

89. Wright Mansell, page 12.

90. Wright Mansell, page 34.

91. Transcript, page 708.

92. Transcript, pages 386-390.

93. PGT submission, 30 December 1991, page 129.

94. Altamont submission, 30 December 1991, Appendix 12.

95. PGT submission, 30 December 1991, Tab H.

96. Transcript, pages 51-58.

97. Transcript, page 439.

98. Transcript, page 789.

99. Transcript, page 441.

100. Transcript, page 783.

101. Altamont submission, 30 December 1991, Appendix 13.

102. Kern River submission, 30 December 1991, pages 16-17.

103. PGT submission, 14 February 1992, in response to Altamont Request numbers 171-174.

104. PGT submission, 30 December 1991, pages 152-156.

105. Altamont submission, 14 February 1992, in response to PGT Request 1104.

106. NOVA submission, 17 January 1992, Chapter 8.

107. NOVA submission, 17 January 1992, Chapter 4.

108. NOVA submission, 17 January 1992, Tables 4.4, 4.8 and 4.12.

109. NOVA submission, 17 January 1992, data in support of figures 5.1, 5.2 and 5.3 are obtained from Chapter 6.

110. NOVA submission, 17 January 1992, Chapter 5.

111. Altamont submission, 30 December 1991, Appendix 17.

112. Transcript, pages 769 - 770.

113. Altamont submission, 31 January 1992, page 19.

114. Altamont submission, 30 December 1991, Appendix 16.

115. Kern River submission, 27 December 1991, page 3.

116. Kern River submission, 27 December 1991, page 10.

117. Transcript, pages 716 - 717.

118. Altamont submission, 12 March 1992.

119. Transcript, pages 685 - 686.

120. Transcript, pages 807 through 812.

121. PGT submission, 30 December 1991, Section 4.E.

122. PGT submission, 30 December 1991, page 117.

123. PGT submission, 30 December 1991, Section 4.E, Exhibit 4-1.

124. PGT submission, 30 December 1991, Section 4.E.

125. Transcript, pages 464 through 472.

126. ANG submission, 14 February 1992, Section III.

127. Amoco Canada Petroleum Company Ltd. submission, 17 January 1992.

128. AEC Oil and Gas Company submission, 16 January 1992.

129. The joint submission of: AEC Oil and Gas Company, Esso Resources Canada, Southern California Edison Company and Western Gas Marketing Limited, 6 April 1992, page 6.

130. Paramount Resources Ltd. submission, 6 April 1992.

131. San Diego Gas & Electric Company submission, 6 April 1992.

132. Kern River submission, February 1992, page 4.

133. Transcript, page 580.

134. Transcript, pages 51-53.

135. PGT submission, 30 December 1991, page 169.

136. PGT submission, 30 December 1991, pages 172-173.

137. Altamont Final Argument, 6 April 1992, page 27.

138. Transcript, page 153.

139. Kern River submission, February 1992, page 11.

140. Transcript, page 500.

141. PGT submission, 30 December 1991, page 44.

142. PGT submission, 14 February 1992, in response to ERCB Request no. 3.

143. PGT submission, 14 February 1992, in response to ERCB Request no. 3 and Transcript, page 517.

144. PGT submission, 30 December 1991, Table 1-10, page 54.

145. Altamont submission, 14 February 1992, Appendix 7, Table 107A.

146. AEC Oil and Gas Company submission, 16 January 1992.

147. PGT submission, 30 December 1991, Table 1-12, page 56.

148. Transcript, page 760.

149. Transcript, page 120.

150. Transcript, page 347.

APPENDIX A

PROCEEDING NO. 911586
ALTAMONT & PGT PIPELINE PROJECTS

LIST OF LETTERS ISSUED BY ERCB REGARDING SCHEDULE AND PROCEDURE

1. Letter dated 4 November 1991 to all interested parties re: Tentative Schedule and Procedure & Preliminary List of Information Requested, a copy of the Order in Council is provided as an attachment.

2. Letter dated 21 November 1991 to all interested parties re: Final Schedule and Procedures & List of Information Requested.

3. Letter dated 22 January 1992 to all interested parties re: an Addendum to the List of Registered Participants.

4. Letter dated 26 February 1992 to all participants re: limited oral examinations.

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4
Telephone (403) 297-8311
Fax (403) 297-7040

4 November 1991

PROCEEDING 911586
CALL FOR INFORMATION
ALTAMONT AND PGT PIPELINE PROJECTS

TO ALL INTERESTED PARTIES
THE PROPOSED ALTAMONT AND PGT PIPELINE PROJECTS

The Lieutenant Governor in Council, by Order in Council 715/91, requires the Energy Resources Conservation Board (Board or ERCB) to conduct a Call for Information on proposals of the Altamont Gas Transmission Company (Altamont) and the Pacific Gas Transmission Company (PGT) to construct and operate separate pipeline facilities for the removal of natural gas from Alberta to markets in the United States of America, particularly California.

The California market may not be able to support more than one of the two projects proposed at this time. There are gaps in the information currently available which may hinder decision-making. The objective is to provide a forum for all interested parties to present and publicly review information relevant to the proposals to assist in their decision-making. The Board will summarize the information presented, without making recommendations, in a report that will be available to the public.

To accomplish this task, the Board has drafted a tentative Schedule and Procedure (Attachment 1) and a preliminary List of Information Requested (Attachment 2). The information request is directed to Altamont and the associated pipeline expansion of the Kern River Gas Transmission Company (Kern River), and to PGT and its associated pipeline expansion of the Alberta Natural Gas Company Ltd (ANG) and Pacific Gas and Electric Company (PG & E); NOVA Corporation of Alberta (NOVA); interested producers, shippers and end-users, and any other parties having an interest in the proceeding.

Parties who wish to participate in this proceeding should register with the Board in writing by 12 November 1991, attention Jim Yu, Assistant Manager, Pipeline Department, at the address above or by FAX at (403) 297-4117.

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

F. J. Mink

F. J. Mink, P.Eng.
Vice Chairman

ATTACHMENT 1 TO PROCEEDING 911586
ALTAMONT AND PGT PIPELINE PROJECTS

TENTATIVE SCHEDULE AND PROCEDURE

The Board proposes to carry out the task in accordance with the following schedule and procedure:

- 14 November 1991 – ERCB to hold a meeting for interested parties to comment on the preliminary List of Information Requested and the tentative Schedule and Procedure. The meeting will commence at 9:00 a.m. in Govier Hall of the Board's Calgary office, 640 Fifth Avenue S.W., Calgary, Alberta, Canada. Parties interested in making oral comments at the meeting should advise the ERCB in writing by 12 November and any written comments should be submitted by the same date; the Board strongly encourages written submission in order to facilitate the discussion.

- 26 November 1991 – ERCB to issue a final List of Information Requested, and Schedule and Procedure, having regard for the comments from interested parties, and a list of all registered participants.

- 31 December 1991 – Deadline for submission of information respecting the Altamont project, PGT expansion, the associated expansion of existing pipeline systems of Kern River, ANG, and PG & E.

- 17 January 1992 – NOVA, interested producers, shippers, and end-users, as well as other interested parties, should file information by this date. It is also the deadline date for any interested parties who wish to participate in the public review of the information filed, to make their intention known in writing to the ERCB and parties who have filed information.

- 31 January 1992 – Deadline for participants to send out written comments and questions on the information filed. The written questions should be copied to all registered parties as early as possible.

- 14 February 1992 – Deadline for filing responses to those written comments and questions mentioned above with copies to all parties.

- 24 February 1992 – ERCB to initiate a formal meeting for all interested parties to question the information filed. The schedule allows 4 weeks for this meeting; the rest of the schedule will be adjusted if the length of the meeting differs from that estimate.

- 3 April 1992 – Deadline for filing any corrections as a result of the meeting.

- 1 May 1992 – ERCB to submit a report summarizing the information collected to the Minister of Energy which will be made available to the public.

Other Matters

- All submissions and correspondence should be forwarded to the attention of Jim Yu, Assistant Manager, Pipeline Department, Energy Resources Conservation Board, 640 Fifth Avenue S.W., Calgary, Alberta, Canada, T2P 3G4. The Board will require 20 copies of each submission and correspondence.

- Communications and queries should also be directed to Jim Yu at (403) 297-8137 or FAX (403) 297-4117.

- The Board will make three complete sets of documents available for public viewing, two at the ERCB's library on the second floor of its Calgary office, and the other at its office in Edmonton.

- Interested parties who wish to obtain copies of initial submissions should request them directly from the submitters.

- The ERCB will continue to accept and begin processing gas removal applications related to these projects during the course of the proceeding. However, recommendations to the Minister of Energy may not be made until the proceeding is finished.

- Information from this proceeding may be used in evaluation of future gas removal applications.

- To obtain additional copies of this letter, please contact the ERCB's Information Services Section at (403) 297-8190 or FAX (403) 297-7040.

4 November 1991

ATTACHMENT 2 TO PROCEEDING 911586
ALTAMONT AND PGT PIPELINE PROJECTS

PRELIMINARY LIST OF INFORMATION REQUESTED

MARKET INFORMATION

General Demand/Supply Information Requirement

- A description of the size of the existing markets for each region (northern California, southern California, and other markets) proposed to be served, listed by end-use category (residential, commercial, industrial, utility electric generation, enhanced oil recovery, non E.O.R., cogeneration, and transportation).

- Forecast of natural gas demand in existing markets and new markets for each end-use category and region including the expected load factor for each market.

- Potential gas supplies from different sources through existing and currently approved pipelines serving the above regions should be identified and projected for at least the next 20 years. A projection of California gas production and storage capability over the forecast period should be included.

Data should be presented in petajoules (PJ) for each year (1 November to 31 October) including at least 20 years into the future. Assumptions concerning population and economic growth, energy prices, and industrial development by region should be explicitly stated.

Contractual Market Information Pertaining to Alberta Gas Exports

- The status of contractual commitment between end-users and shippers of Alberta gas. This information should be provided by each shipper. In the event that contractual arrangements have not been finalized, a status report on negotiations should also be provided.

- A description of the contract terms should be provided by each shipper, including
    - pricing mechanism;
    - provisions for price renegotiation or price reopeners on a periodic basis;
    - provision for arbitration in the event of unsuccessful renegotiation;
    - duration of contract;
    - market commitment (e.g. minimum take requirements) and provisions for reduction of daily contract quantities; and
    - any other relevant contract terms.

EX-ALBERTA PIPELINE COSTS

For each pipeline including Altamont, Kern River, ANG, PGT, and PG & E.

- A detailed tabulation of the volumes to be transported and sold over the first 20 years of operation, the revenues to be collected, and a detailed schedule of costs throughout that period. This information should be provided separately for both California and non-California markets proposed to be served by each pipeline project. Average transportation tolls to each California region should be provided based on both the currently approved rate design for

each project and the most likely alternative scenarios (e.g. rolled-in or partial rolled-in rate design). For non-California markets, the pipeline routing by which such markets would be accessed and the associated transportation costs (on a pipeline-by-pipeline basis) should be indicated.

Data to be expressed in PJ and 1991 $Canadian. Assumptions should be clearly stated and include capital costs per year for each type of expenditure (main line, compression, etc.), Operation and Maintenance (O&M) costs by fixed and variable, overhead costs, depreciation, debt/equity splits and financing costs (including return on equity), taxes, load factors, and the toll methodology used. For ease of comparison, submitters are requested to assume a constant rate of inflation of x% p.a. for all capital and O&M charges, a constant exchange rate of y $Can./$U.S., a U.S. prime lending rate of z% p.a. (Suggested rates are 4.5% p.a. for U.S. and Canadian inflation rates, a Canadian $ valued at 88¢(U.S.), and a U.S. prime lending rate of 8.0% p.a. These assumptions will be finalized following the meeting on 14 November 1991.)

- An assessment of the risks to the above revenue and volume forecasts as they may impact on the netbacks to Alberta. For example, the impact of lower market growth, changes in regulatory policy, and low load factors on producer revenues.

- An outline of the transportation contracts, including duration and any provisions that may allow either party to abrogate the contract in whole or in part.

- The status of the contractual commitment.

- A description of the facilities including their operating parameters and reasons for choosing these parameters.

- A comment on the ability to downsize or phase in the proposed pipelines in the event that forecast demand in California and the relevant non-California markets indicates a need for scaled-down projects. A description of the impact of downsizing on facilities, reliability, timing, and per-unit transportation costs.

- A status report regarding project financing.

- Any known environmental or safety concerns associated with the projects, and their impact on the timing of the proposed pipelines.

INTRA-ALBERTA PIPELINE COSTS

- Estimates of the revenue requirements associated with serving both pipelines as well as each separately, over the first 20 years of operation. The information should explicitly identify facilities, capital costs, and operating expenditures, as described for ex-Alberta pipelines.

- The impact of each alternative on other NOVA customers, including estimated tolls and system reliability.

- The status of the shippers' commitment to NOVA.

GAS SUPPLY

- A description of dedicated project reserves including volumes, supply areas, and suppliers in Alberta, other provinces, and other sources.

- A description of gas purchase contracts including
  - pricing mechanism;
  - provisions for price renegotiation or price reopeners on a periodic basis;
  - provision for aribitration in the event of unsuccessful renegotiation;
  - volume committed;
  - duration of contract;
  - provisions for reduction of daily contract quantities; and
  - any other relevant contract terms.

- The status of contractual supply commitments.

- Forecasts of supply deliverability and plans for deliverability maintenance over the 20-year period beginning 1 November 1993, for each project.

- Assessment of whether there is sufficient gas available under Alberta's current gas removal policies to support either or both proposed projects over the 20-year period beginning 1 November 1993.

OTHER MATTERS

- Any environmental impacts in Alberta resulting from the projects.

- Assessment of whether California represents the most appropriate market for surplus Alberta gas, having regard to the availability and price of other competing sources of gas.

- For each pipeline system a forecast of market prices and system-wide sales revenues, by region, assuming: a) only one project proceeds; and b) assuming both projects are in service by 1 November 1993.

- The expected timing for filing applications and receiving all remaining regulatory approvals in the U.S. and Canada.

- The economic benefit of each project to Alberta and Canada.

- Any other matters which may affect the Alberta public interest.

4 November 1991

Alberta

ORDER IN COUNCIL

APPROVED AND ORDERED,

Gordon Towers

LIEUTENANT GOVERNOR

O.C. 715/91

October 31, 1991

EDMONTON, ALBERTA

Upon the recommendation of the Honourable the Minister of Energy, the Lieutenant Governor in Council, pursuant to section 22 of the Energy Resources Conservation Act,

1. requests the Energy Resources Conservation Board to call for, and make available for public evaluation, information to clarify existing proposals to construct pipelines from Alberta to the California market;

2. requests the Energy Resources Conservation Board to summarize this information without coming to any findings or formulating any recommendations and submit a summarized report to the Minister of Energy which will be made available to the public.

CHAIRMAN

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Telephone (403) 297-8311
Fax (403) 297-7040

21 November 1991

PROCEEDING 911586
CALL FOR INFORMATION
ALTAMONT AND PGT PIPELINE PROJECTS

TO ALL INTERESTED PARTIES

The Lieutenant Governor in Council, by Order in Council 715/91, required the Energy Resources Conservation Board (Board or ERCB) to conduct a Call for Information on proposals of the Altamont Gas Transmission Company (Altamont) and the Pacific Gas Transmission Company (PGT) to construct and operate separate pipeline facilities for the removal of natural gas from Alberta to markets in the United States of America, particularly California.

The California market may not be able to support more than one of the two projects proposed at this time. There are gaps in the information currently available in the public domain which may hinder decision-making. The objective is to provide a forum for all interested parties to present and publicly review information relevant to the proposals to assist in their decision-making. The Board will summarize the information presented, without making recommendations, in a report that will be available to the public.

To accomplish this task, the Board issued on 4 November 1991 a tentative Schedule and Procedure and a preliminary List of Information Requested and held a meeting on 14 November for interested parties to present comments on matters in these two attachments. The Board acknowledges the views expressed by participants at this meeting and has carefully considered all their comments, both oral and written. It has made decisions on all matters except the question of holding a formal meeting to permit oral examination of the filed information. This decision is deferred until after the process of filing written information is completed. The Board's decisions are reflected in the finalized Schedule and Procedure (Attachment 1) and the List of Information Requested (Attachment 2) for carrying out the task.

This Call for Information is directed to Altamont and the associated pipeline expansion of the Kern River Gas Transmission Company (Kern River), and to PGT and the associated pipeline expansion of the Alberta Natural Gas Company Ltd (ANG), Foothills Pipe Lines Ltd. (Foothills), and Pacific Gas and Electric Company (PG & E); NOVA Corporation of Alberta (NOVA); interested producers, shippers, and end-users; and any other parties having an interest in the proceeding. The Board has also prepared a list of Registered Participants (Attachment 3) to facilitate communication among participants.

If you have any questions, please call Mr. Jim Yu at (403) 297-8137.

J. P. Prince, Ph.D.*	E. J. Mink	J. W. Newton
Vice Chairman	Vice Chairman	Acting Board Member

* J. P. Prince, Ph.D. was unavailable for signature but concurs with the contents and with the issuing of this letter.

ATTACHMENT 1 TO PROCEEDING 911586
ALTAMONT AND PGT PIPELINE PROJECTS

SCHEDULE AND PROCEDURE

The Board proposes to carry out the task in accordance with the following schedule and procedure. Note: all parties filing submissions or correspondence should send a copy to all registered participants as listed in Attachment 3, on or before the deadline indicated.

- 30 December 1991 – Deadline for filing information respecting the Altamont project, PGT expansion, the associated expansion of existing pipeline systems of Kern River, ANG, Foothills, and PG & E.
- 17 January 1992 – NOVA, interested producers, shippers, and end-users, as well as other interested parties, should file information by this date. It is also the deadline date for any interested parties who wish to participate in the public review of the information filed, to make their intention known in writing to the ERCB.
- 22 January 1992 – ERCB to issue an addendum to Attachment 3, List of Registered Participants. Parties who have filed information should deliver a copy of their submission to each participant listed on the addendum as soon as possible.
- 31 January 1992 – Deadline for participants to send out written comments and questions on the information filed.
- 14 February 1992 – Deadline for filing responses to those written comments and questions mentioned above.
- 19 February 1992 – ERCB to hold a meeting for registered participants to comment on whether the written information filed can be considered complete and whether oral examination is required for all or only some areas of written information filed. The meeting will commence at 9:00 a.m. in Govier Hall of the Board's Calgary office, 640 Fifth Avenue S.W., Calgary, Alberta, Canada.
- 24 February 1992 – ERCB to initiate, if needed, a formal meeting (9:00 a.m. in Govier Hall) for oral examination.
- The filing date for final statements and the target date for release of the ERCB report will be announced following the above meetings.

Other Matters

- All submissions and correspondence should be forwarded to the attention of Jim Yu, Assistant Manager, Pipeline Department, Energy Resources Conservation Board, 640 Fifth Avenue S.W., Calgary, Alberta, Canada, T2P 3G4. The Board will require 20 copies of each submission and correspondence.

- Communications and queries should also be directed to Jim Yu at (403) 297-8137 or FAX (403) 297-4117.

- The Board will make three complete sets of documents available for public viewing, two at the ERCB library on the second floor of its Calgary office, and the other at its office in Edmonton.

- The ERCB will continue to accept and begin processing gas removal applications for these pipeline projects. However, the Board will not make decisions on these applications until this proceeding is complete. If, at that time, any of the information arising from this proceeding would affect the Board's view of any of the gas removal applications before it, the Board would allow reasonable opportunity to comment.

- To obtain additional copies of this letter, please contact the ERCB's Information Services Section at (403) 297-8190 or FAX (403) 297-7040.

21 November 1991

ATTACHMENT 2 TO PROCEEDING 911586
ALTAMONT AND PGT PIPELINE PROJECTS

LIST OF INFORMATION REQUESTED

MARKET INFORMATION

General Demand/Supply Information Requirement

- A description of the size of the existing markets for each region (northern California, southern California, and other markets) proposed to be served, listed by end-use category (residential, commercial, industrial, utility electric generation, enhanced oil recovery, non-E.O.R., cogeneration, and transportation).

- Forecast of natural gas demand in existing markets and new markets for each end-use category and region including the expected load factor for each market.

- Potential gas supplies from different sources through existing and currently approved pipelines serving the above regions should be identified and projected for at least the next 20 years, including an assessment of the likelihood that such supplies would continue to serve these regions. A projection of California gas production and storage capability over the forecast period should be included.

Data should be presented in petajoules (PJ) for each year (1 November to 31 October) including at least 20 years into the future. Assumptions concerning population and economic growth, energy prices, and industrial development by region should be explicitly stated.

Contractual Market Information Pertaining to Alberta Gas Exports

- The status of contractual commitment between end-users and shippers of Alberta gas. This information should be provided by each shipper. In the event that contractual arrangements have not been finalized, a status report on negotiations should also be provided.

- Actual gas sales contracts between each shipper and end-user. If these cannot be provided then a description of the contract terms should be provided, including:
    - identification of market by end-use category and region as listed above;
    - pricing mechanism;
    - provisions for price renegotiation or price reopeners on a periodic basis;
    - provision for arbitration in the event of unsuccessful renegotiation;
    - duration of contract;
    - market commitment (e.g. minimum take requirements) and provisions for reduction of daily contract quantities; and
    - any other relevant contract terms.

- Comment on whether the proposed sales by each shipper represent an incremental market for Alberta gas. If existing sales in California will be displaced identify the quantity by the source of such supplies (i.e. Alberta, B.C., U.S. domestic, etc.).

EX-ALBERTA PIPELINE COSTS

For each pipeline including Altamont, Kern River, ANG, Foothills, PGT, and PG & E.

- A detailed tabulation of the volumes to be transported and sold over the first 20 years of operation, the revenues to be collected, and a detailed schedule of costs throughout that period. This information should be provided separately for both California and non-California markets proposed to be served by each pipeline project. Average transportation rates forecast to each California region should be provided based on both the currently approved rate design for each project and the most likely alternative scenarios (e.g. rolled-in or partial rolled-in rate design) and the assumed load factor used in the calculations. An assessment of the impact of rolled-in or partial rolled-in rates on existing shippers over the forecast period. For non-California markets, the pipeline routing by which such markets would be accessed and the associated transportation costs (on a pipeline-by-pipeline basis) and rates should be indicated. Identification of the per cent firm versus interruptible service that each project would offer over the forecast period.

  Data to be expressed in PJ and 1991 $Canadian. Assumptions should be clearly stated and include capital costs per year for each type of expenditure (main line, compression, etc.), Operation and Maintenance (O&M) costs by fixed and variable, overhead costs, depreciation, debt/equity splits and financing costs (including return on equity), taxes, load factors, and the rate design used. For ease of comparison, submitters are requested to assume a constant rate of inflation, in Canada and the U.S., of 4.5 per cent p.a. for all capital and O&M charges, a constant exchange rate of 88¢ (U.S.) for the Canadian $, and a U.S. prime lending rate of 8.0 per cent p.a. throughout the forecast period.

- An assessment of the risks to the above revenue and volume forecasts as they may impact on the netbacks to Alberta. For example, the impact on producer revenues of lower market growth, changes in regulatory policy, and low load factors.

- An assessment of impact on transportation rates if forecast deliveries to non-California markets do not materialize.

- Actual transportation contracts for each shipper on the proposed projects and interconnected pipelines.

- The status of the contractual commitment for each shipper on both projects and interconnected pipelines, where transportation contracts are not finalized.

- A description of the facilities including their operating parameters and reasons for choosing these parameters.

- A comment on the ability to downsize or phase in the proposed pipelines in the event that forecast demand in California and the relevant non-California markets indicates a need for scaled-down projects. A description of the impact of downsizing on facilities, reliability, timing, and shipper per-unit transportation costs.

- A status report regarding project financing.

- Any known environmental or safety concerns associated with the projects, and their impact on the costs and the timing of the proposed pipelines.

INTRA-ALBERTA PIPELINE COSTS

- Estimates of the revenue requirements associated with serving both pipelines as well as each separately, over the first 20 years of operation. The information should explicitly identify facilities, capital costs, and operating expenditures, as described for ex-Alberta pipelines.

- The impact of each alternative on other NOVA customers, including estimated tolls and system reliability.

- The status of the shippers' commitment to NOVA.

GAS SUPPLY

- A description of dedicated project reserves including volumes, supply areas, and suppliers in Alberta, other provinces, and other sources.

- Actual gas purchase contracts between each shipper and producers. If these cannot be provided then a description of the contract terms should be provided including:
  - pricing mechanism;
  - provisions for price renegotiation or price reopeners on a periodic basis;
  - provision for aribitration in the event of unsuccessful renegotiation;
  - volume committed;
  - duration of contract;
  - provisions for reduction of daily contract quantities; and
  - any other relevant contract terms.

- The status of contractual supply commitments, where these have not been finalized.

- Forecasts of supply deliverability and plans for deliverability maintenance over the 20-year period beginning 1 November 1993, for each project.

- Assessment of whether there is sufficient gas available under Alberta's current gas removal policies to support either or both proposed projects over the 20-year period beginning 1 November 1993.

OTHER MATTERS

- Any environmental impacts in Alberta resulting from the projects.

- Assessment of whether California represents the most appropriate market for surplus Alberta gas, having regard to the availability and price of other competing sources of gas.

- For each pipeline system a forecast of market prices and system-wide sales revenues, by region, assuming: a) only one project proceeds; and b) assuming both projects are in service by 1 November 1993.

- The expected timing for filing applications and receiving all remaining regulatory approvals in the U.S. and Canada.
- A general description of the side effects of each project on the Alberta and Canadian economies (e.g. the purchases of goods and services).
- Any other matters which may affect the Alberta public interest.

21 November 1991

ATTACHMENT 3 TO PROCEEDING 911586
ALTAMONT AND PGT PIPELINE PROJECTS

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22 January 1992

PROCEEDING 911586
CALL FOR INFORMATION
ALTAMONT AND PGT PIPELINE PROJECTS

TO ALL INTERESTED PARTIES

In its letter dated 21 November 1991, the Board stated that it would issue on 22 January 1992 an addendum to the List of Registered Participants to facilitate communication among participants. Attached is a copy of the addendum.

Participants who have filed information should deliver a copy of their submission to each participant listed on the addendum as soon as possible. Participants who will send out written comments and questions on the information filed and who will respond to the written comments and questions should also send a copy to all registered participants including those listed in the addendum on or before the deadline given in the Board's letter of 21 November 1991.

If you have any questions, please call me at (403) 297-8137.

Yours truly,

JNG Yu

J. N. G. Yu, P. Eng.
Assistant Manager
Pipeline Department

/vcs

ATTACHMENT 3 TO PROCEEDING 911586
ALTAMONT AND PGT PIPELINE PROJECTS

ADDENDUM TO THE LIST OF REGISTERED PARTICIPANTS

A. *ADD THE FOLLOWING TO THE LIST*

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22 January 1992

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Gouvernement du Quebec
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B. DELETE THE FOLLOWING FROM THE LIST

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PROCEEDING 911586
CALL FOR INFORMATION
ALTAMONT AND PGT PIPELINE PROJECTS

26 February 1992

TO ALL PARTICIPANTS

At the meeting held on 19 February 1992, some participants argued the need for an oral examination on grounds that gaps and inconsistencies exist in the information filed to date. Others argued that oral examination is not necessary. Having considered these arguments, the Board has concluded that limited oral examination would be useful to complete its record.

The Board has decided that only the proponent of the Altamont and Kern River expansion project (Altamont) and the proponent of the ANG, Foothills, PGT, and PG&E expansion project (PGT) will be subject to oral examination. The oral examination will be limited to 5 days, with up to 2 days dedicated to each of the two proponents to examine each other's information, and up to 1 day reserved for the Board (half a day to examine each proponent). It will commence at 9:00 am on 23 March 1992 in Govier Hall of the Board's Calgary Office and will close at 5:30 pm on 27 March 1992. The morning sitting hours will be from 9:00 am to 12:30 pm and the afternoon from 2:00 pm to 5:30 pm. There will be no evening sittings. Altamont will be permitted to question PGT's witnesses during the sitting hours of 23 and 24 March only. The morning of 25 March will be for the questioning of PGT's witnesses by Board staff and the Panel. The examination of Altamont's witnesses by PGT will begin in the afternoon of 25 March and must conclude by 12:30 pm on 27 March. The afternoon of 27 March will be for Board staff and the Panel to question Altamont's witnesses.

Each proponent is requested to advise the Board in writing, with a copy to the other proponent, before 9 March 1992, of the areas in which it intends to carry out oral examination.

Any questions other participants may have of either proponent should be forwarded to the attention of Mr. Jim Yu before 16 March 1992. Board staff will endeavour to integrate these questions with their own.

Proponents and other participants are invited to submit final statements on or before 6 April 1992. The Board will provide the Minister of Energy with its report on 30 April 1992. To facilitate the preparation of the report, Board staff may contact proponents and other participants for information or clarification, both before and after the oral examination. Should you have any questions, please call Mr. Jim Yu at (403) 297-8137.

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

F. J. Mink*
Vice Chairman

JWNewton

J. W. Newton
Acting Board Member

* Mr. Mink was not available to sign this letter but agrees with its content.

APPENDIX B

PROCEEDING 911586
ALTAMONT & PGT PIPELINE PROJECTS

LIST OF WRITTEN SUBMISSIONS

A. INITIAL SUBMISSIONS

1. Altamont dated 30 December 1991
2. Kern River dated 27 December 1991
3. PGT - PG&E - ANG - Foothills (2 binders) dated 30 December 1991
4. AEC Oil & Gas Company dated 16 January 1992
5. Joint submission dated 14 January 1992 of
   AEC Oil and Gas Company
   Esso Resources Canada Limited
   Southern California Edison Company
   Western Gas Marketing Limited
6. Amoco Canada Petroleum Company Ltd. dated 17 January 1992
7. Bow Valley Industries Ltd. dated 16 January 1992
8. CanWest Gas Supply Inc.
9. Conwest Exploration Company Limited dated 16 January 1992
10. Conoco Canada Limited
11. Dekalb Energy Canada Ltd. dated 16 January 1992
12. Entech Altamont, Inc. dated 16 January 1992
13. Grand Valley Gas Company
14. IGI Resources Inc. dated 16 January 1992
15. Inverness Resources Inc. dated 17 January 1992
16. Northridge Petroleum Marketing Inc. dated 17 January 1992
17. Northwest Natural Gas Company dated 16 January 1992
18. NOVA Corporation of Alberta dated 17 January 1992
19. Pacific Interstate Company dated 17 January 1992
20. Pan-Alberta Gas Ltd.
21. PanCanadian Petroleum Limited dated 17 January 1992
22. Paramount Resources Ltd. dated 17 January 1992
23. POCO Petroleums Ltd. dated 17 January 1992
24. Joint submission dated 17 January 1992 of
    ProGas Limited
    Union Pacific Fuels, Inc.
25. San Diego Gas & Electric Company

26. Santa Fe Energy Resources, Inc. dated 15 January 1992
27. Summit Resources Limited dated 17 January 1992
28. Suncor Resources Group Inc. dated 17 January 1992
29. Tenngasco Corporation dated 16 January 1992
30. Unigas Corporation dated 17 January 1992
31. Vector Energy Inc. dated 17 January 1992
32. Washington Energy Resources dated 17 January 1992
33. Wes Cana Energy Marketing Inc. dated 17 January 1992
34. Western Gas Resources, Inc. dated 17 January 1992

B. COMMENTS AND QUESTIONS

35. PGT - PG & E - ANG - Foothills dated 31 January 1992
36. Altamont dated 31 January 1992
37. Kern River dated 31 January 1992
38. Joint submission of
    AEC, Esso Resources Canada, Southern California Edison Company and Western Gas Marketing Limited dated 31 January 1992
39. Amerada Hess Canada Ltd. dated 31 January 1992
40. Amoco Canada Petroleum Company Ltd.
41. City of Burbank, City of Glendale and City of Pasadena dated 31 January 1992
42. Czar Resources Ltd. dated 31 January 1992
43. Grand Valley Gas Company dated 31 January 1992
44. Husky Oil dated 31 January 1992
45. Northern Border Pipeline Company dated 31 January 1992
46. Northwest Natural Gas Company dated 31 January 1992
47. Pan-Alberta Gas Ltd. dated 31 January 1992
48. Paramount Resources Ltd. dated 31 January 1992
49. Petro-Canada Resources dated 30 January 1992
50. ProGas Limited & Union Pacific Fuels, Inc. dated 31 January 1992
51. Suncor Resources Group Inc. dated 31 January 1992
52. TransCanada PipeLines dated 30 January 1992
53. Unigas Corporation dated 31 January 1992
54. Vector Energy Inc. dated 31 January 1992
55. Westcoast Energy dated 31 January 1992

C. RESPONSES TO COMMENTS AND QUESTIONS

56. PGT - PG & E - ANG - Foothills dated 14 February 1992
57. Altamont dated 14 February 1992
58. Kern River dated 14 February 1992
59. Amoco Canada Petroleum Company Ltd. dated 14 February 1992
60. Joint submission of
    AEC, Esso Resources Canada, Southern California Edison Company and Western Gas Marketing Limited dated 14 February 1992
61. AEC Oil and Gas Company dated 14 February 1992
62. Entech Altamont, Inc. dated 13 February 1992
63. Grand Valley Gas Company dated 14 February 1992
64. Norcen Energy Resources Limited dated 14 February 1992
65. NOVA Corporation of Alberta dated 14 February 1992
66. ProGas Limited dated 6 February 1992
67. ProGas Limited and Union Pacific Fuels, Inc. dated 14 February 1992
68. San Diego Gas & Electric Company
69. Suncor Resources Group Inc. dated 13 February 1992
70. Wescan Environmental Inc. dated 12 February 1992
71. Western Gas Resources, Inc. dated 14 February 1992
72. Chevron Canada Resources dated 20 February 1992
73. Entech Altamont Inc. dated 18 February 1992
74. Pacific Interstate Transmission Company dated 20 February 1992

D. FURTHER SUBMISSIONS

75. Czar Resources Ltd. dated 26 February 1992
76. Mr. A. L. McLarty's letter (Altamont) dated 9 March 1992 respecting the areas of oral examination.
77. Mr. Terence Dalgleish's letter (PGT) dated 9 March 1992 respecting the areas of oral examination.
78. Mr. Terence Dalgleish's letter (PGT) dated 12 March 1992 respecting the areas of oral examination.
79. Westcan Environmental Inc. dated 12 March 1992
80. Altamont including a report by Brent Friedenberg Associates Ltd. dated 12 March 1992.
81. Mr. Terence Dalgleish's letter (PGT) dated 16 March 1992 concerning the Friedenberg's report.
82. Mr. A. L. McLarty's letter (Altamont) dated 18 March 1992 addressing Mr. Dalgleish's concern of the Friedenberg's report.

83. Western Gas Resources, Inc. dated 1 April 1992.

84. Inverness Resources Inc. dated 16 April 1992.

85. Pacific Interstate Company dated 20 April 1992.

86. Alberta Natural Gas Company Ltd. dated 10 April 1992 confirming maximum volume requirements at Alberta/British Columbia border.

87. Alberta Natural Gas Company Ltd. dated 14 May 1992 re proposed recommissioning of NGL extraction facilities at Cochrane straddle plant.

E. FINAL STATEMENTS

88. Altamont - Kern River dated 6 April 1992.

89. PGT - PG&E - ANG - Foothills dated 6 April 1992.

90. Amoco Canada Petroleum Company Ltd. dated 6 April 1992.

91. Conoco Canada Limited dated 7 April 1992.

92. Conwest Exploration Company Limited dated 6 April 1992.

93. Entech, Inc. dated 3 April 1992.

94. Pacific Interstate Transmission Company dated 6 April 1992.

95. Paramount Resources Ltd. dated 6 April 1992.

96. ProGas Limited dated 6 April 1992.

97. San Diego Gas & Electric Company dated 6 April 1992.

98. Vector Energy Inc. dated 6 April 1992.

99. Westcan Environmental Inc. dated 6 April 1992.

100. Western Gas Resources, Inc. dated 3 April 1992.

101. Joint submission of AEC Oil and Gas Company, Esso Resources Canada, Southern California Edison Company and Western Gas Marketing Limited dated 6 April 1992.

APPENDIX C

Appendix C: Altamont Shipper Information

ALTAMONT	**Shipper** Amoco Energy Trading Corporation	**Shipper Information** Amoco Canada is the largest producer of gas in Canada.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	105.00	102.5	79.77	50.00
Term Bcf	574.9	561.2		
Term years	15	15		
Nova Information Amoco Canada Petroleum Company Ltd. signed an agreement with AETC that allows Altamont to deal directly with Nova.		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements** Kern is obliged to deliver a maximum of 19.3 MMcf/d on the Kern Expansion.	

Market		**Supply**	
Type Alternative markets including Northern California, even though not incremental into the foreseeable future. Plans are to target the California industrial market for those volumes not contracted.		**Type** Amoco Canada corporate reserves pool. Amoco indicated that it would use Rocky Moutain supplies to satisfy its Shell contract; thereafter it will use Alberta gas.	
Location Shell Western E&P Inc. (SWEPI). Thermal Enhanced Recovery project.		**Location** Alberta	
Negotiations Negotiations are still in progress for the 77.5 MMcf/d however Amoco is finalizing a letter of intent for 34 MMcf/d. Additionally, Amoco has proposals to customers in and upstream from California respecting a volume in excess of 200 MMcf/d.		**Negotiations** Amoco Canada expects to sign with AETC, if they do sign they indicate there will be no problem with supply. Amoco's corporate reserve pool is 1.6 Tcf and only 682 Bcf would be required over the 20 years. This would only be 43% of Amoco's pool.	
Volume 25 MMcf/d	**Term** 8.5 years	**Volume** 105 MMcf/d	**Term** 15 years

Amoco Energy Trading Corporation Continued........ **Contract Signed** Yes, for 25 MMcf/d. AETC may buy its way out if SWEPI fails to supply gas.The buyer has a good faith obligation to take 100% and will reimburse at contract price for gas not taken below 75%. If the netback is less AETC can request a price redetermination.	**Contract Signed** No
Regulatory Approval Amoco is in the process of finalizing its applications to the NEB and the ERCB with respect to the Shell contract.	**Comments on Supply** Amoco supplied a deliverability estimate that indicated sufficient deliverability. Amoco supports Altamont and PGT on their conclusions that there is sufficient supply for either or both projects.

Appendix C: Altamont Shipper Information

ALTAMONT	**Shipper** Bow Valley Industries Ltd.	**Shipper Information** Canadian gas producer.

Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	51.50	50	48.32	
Term Bcf		292	264.53	
Term years		16	15	

Nova Information	**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements**

Market	**Supply**
Type	**Type** Volumes will come from properties that Bow Valley owns or controls, or from other sources.
Location	**Location** Alberta, Saskatchewan & British Columbia
Negotiations Continues to pursue long term market opportunities.	**Negotiations**

Volume (MMcf/d)	**Term** (years)	**Volume** 51.5 MMcf/d	**Term** 16 years

Contract Signed No	**Contract Signed** No
Regulatory Approval	**Comments on Supply**

Appendix C: Altamont Shipper Information

ALTAMONT	**Shipper** Chevron U.S.A. Inc.	**Shipper Information** Canadian gas producer.

Capacity	Nova	Altamont	Kern Expansion	Kern Base
MMcf/d	41.19	40	19.33	100.00
Term Bcf	225.5	233.6	105.81	501.9
Term years	15	16	15	15

Nova Information Chevron Canada Resources contracted on Nova.	**Contract** Yes - Wild Horse to Opal	**Downstream Arrangements** 100 MMcf/d for a 10 year term and 75 MMcf/d for a 5 year term thereafter.

Market		Supply	
Type Chevron USA corporate facilities in northern California and at Chevron USA EOR facilities in Southern California. All incremental for Alberta gas and will displace Rocky Mountain supplies.		**Type** Chevron Canada gas.	
Location Northern and southern California.		**Location** Alberta	
Negotiations Chevron Canada expects to execute a contract with Chevron USA Inc.		**Negotiations** Continuing with Chevron USA.	
Volume 40 MMcf/d	**Term** 16 years	**Volume** 40 MMcf/d	**Term** 16 years
Contract Signed No		**Contract Signed** No	
Regulatory Approval		**Comments on Supply** Chevron Canada Resources is presently rationalizing its supply source which will include present uncontracted and contracted reserves, reserve acquisition and additions through planned expenditure in gas prone areas.Third party purchases may also occur.	

Appendix C: Altamont Shipper Information

ALTAMONT	**Shipper** Conoco Inc.	**Shipper Information** Western Canadian gas producer.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	5.20	5		yes - interruptible service only
Term Bcf		27.38		
Term years		15		
Nova Information Conoco Canada Limited contracted with Nova.		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements** Kern River, Northwest, Colorado Interstate, and Questar pipelines.	

Market	**Supply**
Type	**Type** Conoco Canada corporate reserves pool and some from third party purchases. A total of 5 MMcf/d: 2.5 MMcf/d from Conoco and 2.5 MMcf/d from other sources.
Location Currently a major supplier with Pacific NW and Rocky Mountain areas, including Conoco refineries in Billings Montana and Denver Colorado.	**Location** Alberta
Negotiations Currently developing additional markets.	**Negotiations** Will secure supplies from both sources.

Volume 5 MMcf/d	**Term** 15 years	**Volume** 5 MMcf/d	**Term** 15 years

Contract Signed No	**Contract Signed** No
Regulatory Approval Will apply for regulatory permits once market is firm.	**Comments on Supply** Combination of Conoco's Alberta reserves and third party purchases.

ALTAMONT	Shipper Conwest Exploration Company	Shipper Information A resource exploration and production company.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	10.20	10	9.66	
Term Bcf		58.4	52.905	
Term years		16	15	
Nova Information		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements**	

Market		**Supply**	
Type Potentially incremental markets.		**Type** Company supply, existing reserves, acquisitions and recent reserve additions.	
Location Will be selling to customers in both California and Nevada.		**Location** Braeburn, Caroline, West Caroline and Pouce Coupe fields in Alberta.	
Negotiations Negotiating directly with customers and working with a gas marketing company in the US to develop additional supply. Altamont volumes are not specifically targeted to these contracts but may be used.		**Negotiations** Confident that it will meet the gas supply for 20 years.	
Volume (MMcf/d)	**Term** (years)	**Volume** 10.2 MMcf/d	**Term** (years)
Contract Signed No		**Contract Signed** No	
Regulatory Approval Will apply for long term permit however would rely on short term permits if the permits were delayed beyond in-service date.		**Comments on Supply** Due to confidential nature of exploration projects, no data will be supplied.	

Appendix C: Altamont Shipper Information

ALTAMONT	**Shipper** Entech, Inc.	**Shipper Information** Subsidiary of Montana Power Company.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	51.20	50	48.32	
Term Bcf	280.3	273.8	264.53	
Term years	15	15	15	
Nova Information Altana Exploration Company contracted with Nova.		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements** Opportunity for marketing on Colorado Interstate, Northwest and Questar and then in turn to Pacific Northwest.	

Market		**Supply**	
Type Entech, Inc. currently has two cogeneration facility contracts in its market portfolio which could be supplied via Altamont deliveries of Canadian gas. Entech is negotiating with other potential markets.		**Type** Uncontracted reserves in Alberta, (see comments below).	
Location End-use markets are in Texas but Entech would take deliveries of Canadian gas at Nova.		**Location** Existing reserves are located primarily in Caroline, Monitor/ Provost and Southeastern Alberta.	
Negotiations Negotiations are ongoing with potential markets to be included in Entech's market portfolio. These include potential markets in the Pacific Northwest, Rocky Mountain area and Southwest.		**Negotiations** Contracted reserves in Alberta - 38 Bcf. Uncontracted reserves in Alberta - 97 Bcf, of which 64 Bcf will be remaining upon contract expiration dates. Up to 150 Bcf through planned acquisition and exploration activities. The rest to be third party supply.	
Volume 26.1 MMcf/d minimum and 36.4 MMcf/d maximum. On cogeneration projects.	**Term** 12 to 15 years	**Volume** 36.2 MMcf/d (owned supply) and 15 MMcf/d (third party).	**Term** 12 to 15 years

Entech, Inc. continued......... **Contract Signed** Contracts have been signed on the cogeneration markets. No contracts have been signed with other potential markets.	 **Contract Signed** No third party supply has been contracted at this date.
Regulatory Approval Will apply in the future.	**Comments on Supply** 97 Bcf from Altana and Roan but only 17 Bcf available by Nov 1993; the rest due later in 1990's. Roan recently acquired Shell Manyberries, therefore supply could go as high as 150 Bcf. Third party could supply 15 MMcf/d.

Appendix C: Altamont Shipper Information

ALTAMONT	Shipper Inverness Resources Inc.	Shipper Information Canadian gas producer.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	5.10	5	4.83	
Term Bcf		54.75	26.455	
Term years		30	15	
Nova Information No comment from Inverness.		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements**	

Market		Supply	
Type Incremental market.		**Type** From uncontracted reserves in Alberta.	
Location		**Location** Alberta	
Negotiations Will seek out short and long term markets.		**Negotiations** Inverness is negotiating with prospective end-users of gas.	
Volume (MMcf/d)	**Term** (years)	**Volume** 5.1 MMcf/d	**Term** (years)
Contract Signed No		**Contract Signed** No	
Regulatory Approval Upon conclusion of negotiations, Inverness will file an application with the ERCB for long term removal permits. Short-term permits may also be requested for any interim period.		**Comments on Supply**	

Appendix C: Altamont Shipper Information

ALTAMONT	**Shipper** Northridge Alberta Gas Sales Ltd.	**Shipper Information** North American gas marketer.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	11.00	10.309		
Term Bcf		56.44		
Term years		15		
Nova Information No comment from Northridge: Altamont says they have receipt capacity.		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements** In the process of arranging for downstream service.	

Market		**Supply**	
Type		**Type**	
Location		**Location**	
Negotiations Currently pursuing markets.		**Negotiations** In the process of making supply arrangements.	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed No		**Contract Signed** No	
Regulatory Approval		**Comments on Supply**	

Appendix C: Altamont Shipper Information

ALTAMONT	**Shipper** Pacific Interstate Company	**Shipper Information** Acting agent for SoCalGas.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	205.10	200	193.27	
Term Bcf		1095	1058.1	
Term years		15	15	
Nova Information Pacific Interstate Company has no obligation to Nova.		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements** PIC has entered into four separate contracts each for 48.316 MMcf/d.	

Market		**Supply**	
Type Core market only.		**Type** Alberta gas supplies.	
Location SoCalGas (Southern California Gas Company). This is PIC's sole customer.		**Location** Alberta	
Negotiations Pending.		**Negotiations** Pending.	
Volume 200 MMcf/d	**Term** 15 years	**Volume** 200 MMcf/d	**Term** 15 years
Contract Signed No		**Contract Signed** No	
Regulatory Approval PIC suppliers will have the obligation to file applications with the ERCB requesting the issuance of removal permits to satisfy their gas sales commitments.		**Comments on Supply** Gas procurement and transportation commitments subject to CPUC approval.	

ALTAMONT	Shipper Sante Fe Energy Resources	Shipper Information USA gas producer.

Capacity	Nova	Altamont	Kern Expansion	Kern Base
MMcf/d	20.00	20	19.33	
Term Bcf		124.1	105.81	
Term years		17	15	

Nova Information	Contract	Other Downstream Arrangements
No comment from Santa Fe. Altamont says they have receipt capacity with Amoco Canada Limited.	Yes - Wild Horse to Opal	Constructing its own lines to take delivery from Kern.

Market	Supply
Type Its own EOR facilities in Kern County, California. Sales will be incremental and will displace U.S. domestic gas (Rocky Mountain and Permian Basin).	**Type** Amoco Canada Corporate reserves pool.
Location Kern County, California.	**Location** Alberta
Negotiations	**Negotiations** The contract is with Amoco over a 2-year term with a 1 year extension. They have also entered into a joint venture with Bow Valley for deep Devonian gas.
Volume 20 MMcf/d **Term** years	**Volume** 20.5 MMcf/d **Term** (years)
Contract Signed It is a market. If the shipper is not allocated its full MDQ as requested under open season it may terminate the agreement by providing written notice within 3 days after notification of this volume reduction.	**Contract Signed** Yes
Regulatory Approval	**Comments on Supply** Provided a description of the contract.

<table>
<tr><td colspan="2">ALTAMONT</td><td colspan="2">Shipper
Tenngasco Corporation</td><td colspan="4">Shipper Information
A wholly owned subsidiary of Tenneco in Houston.</td></tr>
<tr><td colspan="2">Capacity</td><td colspan="2">Nova</td><td>Altamont</td><td colspan="2">Kern Expansion</td><td>Kern Base</td></tr>
<tr><td colspan="2">MMcf/d</td><td colspan="2">96.00</td><td>94.991</td><td colspan="2">28.99</td><td></td></tr>
<tr><td colspan="2">Term Bcf</td><td colspan="2"></td><td>554.7</td><td colspan="2">158.72</td><td></td></tr>
<tr><td colspan="2">Term years</td><td colspan="2"></td><td>16</td><td colspan="2">15</td><td></td></tr>
<tr><td colspan="4">Nova Information
Altamont supplying but did not give an exact volume. Assume 96 MMcf/d</td><td>Contract
Yes - Wild Horse to Opal</td><td colspan="3">Other Downstream Arrangements</td></tr>
<tr><td colspan="4">Market</td><td colspan="4">Supply</td></tr>
<tr><td colspan="4">Type
Two thirds will go to LDC's in California and one third will be for a cogeneration plant in California.</td><td colspan="4">Type
Alberta gas supplies.</td></tr>
<tr><td colspan="4">Location
California</td><td colspan="4">Location
Alberta</td></tr>
<tr><td colspan="4">Negotiations
Still in progress.</td><td colspan="4">Negotiations
Well advanced with precedent agreements or letters</td></tr>
<tr><td colspan="2">Volume (MMcf/d)</td><td colspan="2">Term (years)</td><td colspan="2">Volume (MMcf/d)</td><td colspan="2">Term (years)</td></tr>
<tr><td colspan="4">Contract Signed</td><td colspan="4">Contract Signed
No</td></tr>
<tr><td colspan="4">Regulatory Approval</td><td colspan="4">Comments on Supply
These are with Progas, Canadian Hunter and Brymore Energy Ltd.</td></tr>
</table>

ALTAMONT	Shipper Union Pacific Fuels, Inc.	Shipper Information Texas based marketing company.		
Capacity	**Nova**	**Altamont**	**Kern Expansion**	**Kern Base**
MMcf/d	51.00	50	28.99	100.00
Term Bcf	279.2	274.5		
Term years	15	15		
Nova Information ProGas Limited contracted with Nova.		**Contract** Yes - Wild Horse to Opal	**Other Downstream Arrangements** Colorado Interstate, Quester, Northwest and Kern Expansion.	

Market		**Supply**	
Type Los Angeles Department of Water Power, Shell Western E & P Oildale cogeneration partners and various cogen plants.		**Type** ProGas contracted reserves from over 200 producers	
Location Destined to California although some gas will go to the Midwest and possibly the eastern US.		**Location** Primarily in Alberta, but some in BC.	
Negotiations Complete.		**Negotiations** Signed agreement with Progas and Union Pacific	
Volume 50 MMcf/d	**Term** 5 to 23 years	**Volume** 50 MMcf/d	**Term** 15 years
Contract Signed Yes. If the shipper is not allocated its full MDQ as requested under open season it may terminate the agreement by providing written notice within 3 days after notification of this volume reduction.		**Contract Signed** Yes	
Regulatory Approval Submiited removal permit to the ERCB on October 30, 1991.		**Comments on Supply** First sale of gas by Progas to California market. Remaining reserves 3.6 Tcf in Alberta and 0.3 Tcf in B.C..	

Appendix C: Altamont Shipper Information

<table>
<tr><td colspan="2">ALTAMONT</td><td colspan="2">Shipper
Wes Cana Energy Marketing (U.S.) Inc.</td><td colspan="5">Shipper Information
Marketing arm of SaskOil Energy Marketing Inc.</td></tr>
<tr><td colspan="2">Capacity</td><td colspan="2">Nova</td><td colspan="2">Altamont</td><td colspan="2">Kern Expansion</td><td>Kern Base</td></tr>
<tr><td colspan="2">MMcf/d</td><td colspan="2">33.00</td><td colspan="2">31</td><td colspan="2"></td><td></td></tr>
<tr><td colspan="2">Term Bcf</td><td colspan="2"></td><td colspan="2">169.7</td><td colspan="2"></td><td></td></tr>
<tr><td colspan="2">Term years</td><td colspan="2"></td><td colspan="2">15</td><td colspan="2"></td><td></td></tr>
<tr><td colspan="4">Nova Information
No comment from Wes Cana; Altamont says they have receipt capacity.</td><td colspan="2">Contract
Yes - Wild Horse to Opal</td><td colspan="3">Other Downstream Arrangements
Currently in the process of arranging downstream capacity on Kern River Expansion for 30 MMcf/d.</td></tr>
<tr><td colspan="4">Market</td><td colspan="5">Supply</td></tr>
<tr><td colspan="4">Type
Cogeneration, industrial and utility generation.</td><td colspan="5">Type
Mostly from small independent producers.</td></tr>
<tr><td colspan="4">Location
Focussing on Southern California, Nevada, Utah and New Mexico.</td><td colspan="5">Location
Alberta and Saskatchewan.</td></tr>
<tr><td colspan="4">Negotiations
Currently pursuing a variety of end-use markets.</td><td colspan="5">Negotiations
Currently negotiating with a number of Alberta and Saskatchewan producers.</td></tr>
<tr><td colspan="2">Volume (MMcf/d)</td><td colspan="2">Term (years)</td><td colspan="3">Volume (MMcf/d)</td><td colspan="2">Term (years)</td></tr>
<tr><td colspan="4">Contract Signed
No</td><td colspan="5">Contract Signed
No</td></tr>
<tr><td colspan="4">Regulatory Approval</td><td colspan="5">Comments on Supply
It is expected that Saskatchewan Oil and Gas Corporation will also provide some portion of the gas.</td></tr>
</table>

Appendix C: Altamont Shipper Information

<table>
<tr><td>ALTAMONT</td><td>Shipper
Western Gas Resources, Inc.</td><td colspan="3">Shipper Information
A Denver-based company with a marketing arm to ensure markets for its plant production.</td></tr>
<tr><td>Capacity</td><td>Nova</td><td>Altamont</td><td>Kern Expansion</td><td>Kern Base</td></tr>
<tr><td>MMcf/d</td><td>51.20</td><td>50</td><td></td><td></td></tr>
<tr><td>Term Bcf</td><td></td><td>273.8</td><td></td><td></td></tr>
<tr><td>Term years</td><td></td><td>15</td><td></td><td></td></tr>
<tr><td colspan="2">Nova Information
Nova assigned to Altamont.</td><td>Contract
Yes - Wild Horse to Opal</td><td colspan="2">Other Downstream Arrangements
Colorado Interstate, Questar, NGPL, PEPL, Trail Blazer, KN, Williams Northern Natural, Northwest and perhaps Kern Expansion.</td></tr>
</table>

<table>
<tr><td colspan="2">Market</td><td colspan="2">Supply</td></tr>
<tr><td colspan="2">Type
Incremental markets for existing and new customers in the Western US and supplemental to Rocky Mountain supply.</td><td colspan="2">Type
Alberta producers and aggregators.</td></tr>
<tr><td colspan="2">Location
Currently sells to western US.</td><td colspan="2">Location
Alberta</td></tr>
<tr><td colspan="2">Negotiations
Currently sells to San Diego Gas & Electric, PG&E, Sierra Pacific, Southern California Gas Company, Southern California Edison, Los Angeles Department of Water and Power, City of Burbank, City of Long Beach and various other end-users.</td><td colspan="2">Negotiations
Currently negotiating with a number of Alberta producers and aggregators.</td></tr>
<tr><td>Volume 50 MMcf/d</td><td>Term (years)</td><td>Volume 51.2 MMcf/d</td><td>Term 15 years</td></tr>
<tr><td colspan="2">Contract Signed
No</td><td colspan="2">Contract Signed
No</td></tr>
<tr><td colspan="2">Regulatory Approval
Will file for long term permits by the time Altamont goes into service. Short term will be used in the interim.</td><td colspan="2">Comments on Supply</td></tr>
</table>

<table>
<tr><td>ALTAMONT SUMMARY</td><td>Shipper
Total</td><td colspan="3">Shipper Final Page</td></tr>
<tr><td>Capacity</td><td>Nova</td><td>Altamont</td><td>Kern Expansion</td><td>Kern Base</td></tr>
<tr><td>MMcf/d</td><td>736.69</td><td>718.8</td><td>480.80</td><td>250.00</td></tr>
<tr><td>Term years</td><td>15</td><td>15, 16 or 30</td><td></td><td></td></tr>
<tr><td colspan="2">Nova Information
Altamont indicated that contracts between Altamont and its shippers or suppliers regarding security of Nova construction is proprietary and confidential. Altamont executed the expenditure authorization and security agreements with Nova.</td><td>Contract</td><td colspan="2">Other Downstream Arrangements
Kern River originally reserved 452 MMcf/d for Kern expansion shippers. This was changed to a range of 500 to 550 MMcf/d, in the oral cross-examination.</td></tr>
</table>

Market	**Supply**
Type The target market is southern California however, direct marketing opportunities exist upstream of California in Nevada and Utah. Additional markets in the Pacific Northwest, Midwestern U.S., and even northern California were given as alternatives.	**Type** Supplies to come from corporate reserves or uncontracted reserves of many smaller producers.
Negotiations While negotiations are underway for many of the Altamont shippers only three contracts have been signed. These are with Amoco, Sante Fe Energy, and Union Pacific Fuels.	**Negotiations** With the exception of Amoco and ProGas Limited, suppliers have not yet identified specific fields nor dedicated reserves to the Altamont project. This is expected to conclude later this year.
Volume 426.4 MMcf/d, as submitted by Altamont	**Volume** 323.2 MMcf/d, as submitted by Altamont
Contract Signed *ERCB review of this Appendix :* *95 MMcf/d signed and* *472.49 MMcf/d under negotiation.*	**Contract Signed**
Regulatory Approval Altamont shippers indicated they would file for the appropriate permits and licences once the supply and markets arrangements were firmed up.	**Comments on Supply**

	ALTAMONT	Capacity							Nova		Kern		Kern Base
	Shipper	Daily	Annual	Term	Daily	Annual	Term	Term	Daily	Daily	Daily	Daily	Daily
		MMcf/d	Bcf	Bcf	E6m3/d	E6m3	E9m3	years	MMcf/d	E6m3/d	MMcf/d	E6m3/d	MMcf/d
1	**Amoco Energy Trading**	**102.5**	**37.41**	**561.19**	**2.89**	**1054.91**	**15.82**	**15**	**105.00**	**2.96**	**79.77**	**2.25**	**50.00**
2	Bow Valley Industries Ltd.	50	18.25	292.00	1.41	514.59	8.23	16	51.50	1.45	48.32	1.36	
3	**Chevron U.S.A. Inc.**	**40**	**14.60**	**233.60**	**1.13**	**411.67**	**6.59**	**16**	**41.19**	**1.16**	**19.33**	**0.54**	**100.00**
4	Conoco Inc.	5	1.83	27.38	0.14	51.46	0.77	15	5.20	0.15			interruptible
5	**Conwest Exploration Company**	**10**	**3.65**	**58.40**	**0.28**	**102.92**	**1.65**	**16**	**10.20**	**0.29**	**9.66**	**0.27**	
6	Entech,Inc.	50	18.25	273.75	1.41	514.59	7.72	15	51.20	1.44	48.32	1.36	
7	**Inverness Resources Inc.**	**5**	**1.83**	**54.75**	**0.14**	**51.46**	**1.54**	**30**	**5.10**	**0.14**	**4.83**	**0.14**	
8	Northridge Alberta Gas Sales Ltd.	10.309	3.76	56.44	0.29	106.10	1.59	15	11.00	0.31			
9	**Pacific Interstate Company**	**200**	**73.00**	**1095.00**	**5.64**	**2058.37**	**30.88**	**15**	**205.10**	**5.78**	**193.27**	**5.45**	
10	Sante Fe Energy Resources	20	7.30	124.10	0.56	205.84	3.50	17	20.00	0.56	19.33	0.54	
11	**Tenngasco Corporation**	**94.991**	**34.67**	**554.75**	**2.68**	**977.63**	**15.64**	**16**	**96.00**	**2.71**	**28.99**	**0.82**	
12	Union Pacific Fuels, Inc.	50	18.25	274.50	1.41	514.59	7.72	15	51.00	1.44	28.99	0.82	100.00
13	**Wes Cana Energy Marketing**	**31**	**11.32**	**169.73**	**0.87**	**319.05**	**4.79**	**15**	**33.00**	**0.93**			
14	Western Gas Resources, Inc.	50	18.25	273.75	1.41	514.59	7.72	15	51.20	1.44			
	Total	**718.8**	**262.36**	**4049.33**	**20.27**	**7397.77**	**114.16**		**736.69**	**20.77**	**480.80**	**13.55**	**250.00**

APPENDIX D

Appendix D: PGT Shipper Information

PGT	**Shipper** BC Gas Inc.	**Shipper Information** Domestic shipper		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d			5.00	
Term Bcf			27.38	
Term years			15	
Additional Information Not shipping on Nova as this is B.C. gas.		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type Domestic		**Type**	
Location		**Location**	
Negotiations		**Negotiations**	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed No		**Contract Signed**	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	Shipper BP Resources Canada Limited	Shipper Information Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d		9.96		
Term Bcf		58.18		
Term years		16		
Additional Information		**Contract** Yes - Stanfield to Malin	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type		**Type**	
Location		**Location**	
Negotiations		**Negotiations**	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed No		**Contract Signed**	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

<table>
<tr><td>PGT</td><td>Shipper
Canwest Gas Supply USA Inc.</td><td colspan="3">Shipper Information - Page 1 of 3
Gas supply aggregator based in BC.</td></tr>
<tr><td>Capacity</td><td>Nova</td><td>PGT Expansion</td><td>ANG Expansion</td><td>PG&E</td></tr>
<tr><td>MMcf/d</td><td>28.3 total</td><td>15.27</td><td>27.70 total of pages 1 to 3</td><td></td></tr>
<tr><td>Term Bcf</td><td></td><td>89.16</td><td>151.67</td><td></td></tr>
<tr><td>Term years</td><td></td><td>16</td><td>15</td><td></td></tr>
<tr><td colspan="2">Additional Information
It was difficult to determine the volume split between Can West Supply Inc. and Can West USA Inc. PGT submitted three different volumes, thus three pages.</td><td>Contract
Yes - Stanfield to Malin</td><td colspan="2">Other Downstream Arrangements

Comments
Establishing transportation agreement with PG&E.</td></tr>
</table>

<table>
<tr><td colspan="2">Market</td><td colspan="2">Supply</td></tr>
<tr><td colspan="2">Type
No information provided on market type.</td><td colspan="2">Type
Supply pool of 175 producers. Canwest is a gas aggregator based in BC.</td></tr>
<tr><td colspan="2">Location
Intends to market in California.</td><td colspan="2">Location
B.C., mainly, but some from Alberta.</td></tr>
<tr><td colspan="2">Negotiations
In the process of establishing gas sales arrangements with its market.</td><td colspan="2">Negotiations
Nothing mentioned.</td></tr>
<tr><td>Volume (MMcf/d)</td><td>Term (years)</td><td>Volume (MMcf/d)</td><td>Term (years)</td></tr>
<tr><td colspan="2">Contract Signed
No</td><td colspan="2">Contract Signed
No</td></tr>
<tr><td colspan="2">Regulatory Approval</td><td colspan="2">Comments on Supply</td></tr>
</table>

PGT	Shipper Canwest Gas Supply USA, Inc.	Shipper Information - Page 2 of 3.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d		26.66		
Term Bcf		291.93		
Term years		30		
Additional Information It was difficult to determine the volume split between Can West Supply Inc. and Can West USA Inc. PGT submitted three different volumes, thus three pages.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		**Supply**	
Type		**Type**	
Location		**Location**	
Negotiations		**Negotiations**	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed No		**Contract Signed**	
Regulatory Approval		**Comments on Supply**	

<table>
<tr><td>PGT</td><td>Shipper
Canwest Gas
Supply USA, Inc.</td><td colspan="3">Shipper Information - Page 3 of 3.</td></tr>
<tr><td>Capacity</td><td>Nova</td><td>PGT Expansion</td><td>ANG Expansion</td><td>PG&E</td></tr>
<tr><td>MMcf/d</td><td></td><td>34.02</td><td></td><td></td></tr>
<tr><td>Term Bcf</td><td></td><td>372.50</td><td></td><td></td></tr>
<tr><td>Term years</td><td></td><td>30</td><td></td><td></td></tr>
<tr><td colspan="2">Additional Information
It was difficult to determine the volume split between Can West Supply Inc. and Can West USA Inc. PGT submitted three different volumes, thus three pages.</td><td>Contract
Yes - Stanfield to Malin</td><td colspan="2">Other Downstream Arrangements

Comments
Establishing transportation agreement with PG&E.</td></tr>
</table>

<table>
<tr><td colspan="2">Market</td><td colspan="2">Supply</td></tr>
<tr><td colspan="2">Type</td><td colspan="2">Type</td></tr>
<tr><td colspan="2">Location</td><td colspan="2">Location</td></tr>
<tr><td colspan="2">Negotiations</td><td colspan="2">Negotiations</td></tr>
<tr><td>Volume (MMcf/d)</td><td>Term (years)</td><td>Volume (MMcf/d)</td><td>Term (years)</td></tr>
<tr><td colspan="2">Contract Signed
No</td><td colspan="2">Contract Signed</td></tr>
<tr><td colspan="2">Regulatory Approval</td><td colspan="2">Comments on Supply</td></tr>
</table>

Appendix D: PGT Shipper Information

PGT	**Shipper** Cascade Natural Gas Corporation	**Shipper Information** A U.S. LDC based in Washington and Oregon.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d		3.62	3.75	
Term Bcf		39.64	41.01	
Term years		30	30	
Additional Information See IGI, they are the supplier and have the Nova contract. The ANG volume is an annual average of 3.75 MMcf/d with a winter volume of 7.49 MMcf/d.		**Contract** Yes - Kingsgate to Oregon	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type LDC market.		**Type** Unigas Corporation, POCO Petroleum Ltd. and Grand Valley Gas Company gas.	
Location Pacific Northwest and various points of inter-connection in Oregon between PGT mainline and Cascade distribution system.		**Location** Alberta	
Negotiations		**Negotiations** Arranged for gas supply from IGI Resources.	
Volume (MMcf/d)	**Term** (years)	**Volume** 8 (MMcf/d)	**Term** 15 (years)
Contract Signed No		**Contract Signed** Letter of intent.	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	**Shipper** Chevron U.S.A., Inc.	**Shipper Information - Page 1 of 2.** Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	53.1 total for pages 1 to 2	30.47	52.00 total for pages 1 to 2	
Term Bcf	290.72	333.64		
Term years	15	30	N/A	
Additional Information Chevron Canada Resources will ship on Nova and ANG. Chevron USA Inc. will ship on PGT and PG&E.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** 30 years from PGT expansion start. **Comments** Establishing transportation agreement with PG&E. Nova and ANG capacity are for Malin and Stanfield delivery points.	

Market		**Supply**	
Type No information provided on market type.		**Type** Chevron Canada Resources gas.	
Location Malin volumes go to Chevron corporate facilities in California.		**Location** Alberta	
Negotiations In the process of negotiating with Chevron USA.		**Negotiations** Chevron Canada is negotiating with Chevron USA.	
Volume 30.47 MMcf/d	**Term** 30 years	**Volume** 30.47 MMcf/d	**Term** 30 years
Contract Signed No		**Contract Signed** No	
Regulatory Approval		**Comments on Supply** Chevron Canada Resources is presently rationalizing its supply source including uncontracted and contracted reserves, reserves acquisition, and additions, through planned expenditures in gas prone areas. Third party purchases may occur as required.	

PGT	Shipper Chevron U.S.A., Inc.	Shipper Information - Page 2 of 2. Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d		19.44		
Term Bcf		212.8		
Term years		30		
Additional Information Chevron Canada Resources will ship on Nova and ANG. Chevron USA Inc. will ship on PGT and PG&E.		**Contract** Yes - Kingsgate to Stanfield	**Other Downstream Arrangements** 30 years from PGT start. **Comments** Establishing transportation agreement with PG&E. Nova and ANG capacity are for Malin and Stanfield delivery points.	

Market		Supply	
Type No information provided on market type.		**Type** Chevron Canada Resources gas.	
Location Stanfield volumes are currently under negotiation with markets in the Pacific Northeast.		**Location** Alberta	
Negotiations In the process of negotiating with Chevron USA.		**Negotiations** Chevron Canada is negotiating with Chevron USA.	
Volume 19.4 MMcf/d	**Term** 30 years	**Volume** 19.4 MMcf/d	**Term** 30 years
Contract Signed No		**Contract Signed** No	
Regulatory Approval		**Comments on Supply** Chevron Canada Resources is rationalizing its supply source including uncontracted and contracted reserves, reserves acquisition and additions through planned expenditures in gas prone areas. Third party purchases may occur as required.	

Appendix D: PGT Shipper Information

PGT	**Shipper** City of Burbank	**Shipper Information** Municipal electric utility.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	4.91	4.82	4.82	4.66
Term Bcf	26.88	52.78	26.39	51.03
Term years	15	30	15	30
Additional Information Unigas will be the shipper on Nova.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Firm agreement with PG&E and in the process of being executed.	

Market		**Supply**	
Type Municipal electric utility for Burbank, UEG (utility electric generation).		**Type** Six Alberta producers. Archer Resources Ltd., APL Oil and Gas Ltd., Cooperative Energy Development Corporation, Pinnacle Resources Ltd.	
Location City of Burbank		**Location** Alberta	
Negotiations Contract with Unigas. The Cities are looking for a more reliable source and a better environmental fuel. When curtailment exists they have to look for a greater portion of their electrical needs from third party electric sources or use electric generation units with oil.		**Negotiations** Complete	
Volume 4.817 MMcf/d	**Term** 6 years	**Volume** 20.5 MMcf/d	**Term** (years)
Contract Signed Yes - Evergreen provision.		**Contract Signed** Yes	
Regulatory Approval Filed a long term import application with the US DOE for its purchase arrangement with Unigas Corporation.		**Comments on Supply** Reserves and deliverability plots were included in the Unigas submission, tab 10.	

PGT	Shipper City of Glendale	Shipper Information Municipal electric utility.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	4.2	3.97	4.07	3.92
Term Bcf	23.00	43.47	44.57	49.92
Term years	15	30	30	30
Additional Information Unigas will be the shipper on Nova.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		Supply	
Type Municipal electric utility for Glendale, UEG (utility electric generation).		**Type** Six Alberta producers. Archer Resources Ltd., APL Oil and Gas Ltd., Cooperative Energy Development Corporation, Pinnacle Resources Ltd.	
Location City of Glendale		**Location**	
Negotiations Contract with Unigas. The Cities are looking for a more reliable source and a better environmental fuel. When curtailment exists they have to look for a greater portion of their electrical needs from third party electric sources or use electric generation units with oil.		**Negotiations** Complete	
Volume 4.074 MMcf/d	**Term** 6 years	**Volume** (MMcf/d)	**Term** (years)
Contract Signed Yes - Evergreen provision.		**Contract Signed** Yes	
Regulatory Approval		**Comments on Supply** Reserves and deliverability plots were included in the Unigas submission, tab 10.	

Appendix D: PGT Shipper Information

PGT	**Shipper** City of Pasadena	**Shipper Information** Municipal electric utility.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	4.2	3.97	4.07	3.92
Term Bcf	23.00	43.47	44.57	49.92
Term years	15	30	30	30
Additional Information Unigas will be the shipper on Nova.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		**Supply**	
Type Municipal electric utility for Pasedena, UEG (utility electric generation).		**Type** Six Alberta producers. Archer Resources Ltd., APL Oil and Gas Ltd., Cooperative Energy Development Corporation, Pinnacle Resources Ltd.	
Location City of Pasadena		**Location** Alberta	
Negotiations Contract with Unigas. The Cities are looking for a more reliable source and a better environmental fuel. When curtailment exists they have to look for a greater portion of their electrical needs from third party electric sources or use electric generation units with oil.		**Negotiations** Complete	
Volume 4.074 MMcf/d	**Term** 6 years	**Volume** (MMcf/d)	**Term** (years)
Contract Signed Yes - Evergreen provision.		**Contract Signed** Yes	
Regulatory Approval		**Comments on Supply** Reserves and deliverability plots were included in the Unigas submission, tab 10.	

PGT	Shipper Dekalb Energy Company Ltd.	Shipper Information Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	12.1	11.43	11.87	
Term Bcf	66.25	125.11	64.99	
Term years	15	30	15	

Additional Information Dekalb Energy Canada will be the shipper on Nova and ANG.	**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.

Market		Supply	
Type Dekalb will replace California-sourced gas that Dekalb is currently selling to a cogeneration facility that is on decline.		**Type** Dekalb's own gas supplies; currently uncontracted.	
Location Northern California		**Location** 350 Bcf of proven gas reserves in Alberta with 200 Bcf uncontracted.	
Negotiations The specific terms and conditions for the sale to the cogeneration facility have not been finalized. Negotiations were proceeding along fine until the political climate changed.		**Negotiations**	
Volume MMcf/d	**Term** years	**Volume** MMcf/d	**Term** years
Contract Signed No		**Contract Signed** No need	
Regulatory Approval Dekalb Energy Canada will hold the ERCB and NEB removal permit and export licence.		**Comments on Supply** Dekalb plans to maintain its aggressive pursuit of additional natural gas reserves through exploration and acquisition.	

PGT	**Shipper** IGI Resources, Inc.	**Shipper Information - Page 1 of 3.** U.S. gas marketer. IGI acts as an agent for three LDC in seven states.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	7.3	6.96 total of pages 1 to 3	7.00 total of pages 1 to 3	
Term Bcf		76.18	51.10	
Term years		30	20	
Additional Information Grand Valley Gas Company will ship on Nova, on behalf of IGI.		**Contract** Yes - Kingsgate to Stanfield	**Other Downstream Arrangements** InterMountain Gas Company is a firm transportation customer on Northwest. **Comments** No comment on Northwest negotiations.	

Market		**Supply**	
Type 3 LDCs and 150 industrial end-user customers.		**Type** Several Canadian producers and Grand Valley Gas Company.	
Location Washington, Oregon, Idaho, Nevada, Utah, Colorado and California.		**Location**	
Negotiations Purchase is for the winter season. Provision whereby Cascade agrees to reimburse IGI for IGI costs on Nova.		**Negotiations** Signed letter of intent	
Volume 8 MMcf/d	**Term** 15 years	**Volume** (MMcf/d)	**Term** 15 years
Contract Signed Yes - Cascade Natural Gas		**Contract Signed** Letter of intent.	
Regulatory Approval Poco has received NEB authorization DOE(Order No. 507-A) and removal authority from the ERCB on 12 December 1987 (GR 87-62).		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	Shipper IGI Resources, Inc.	Shipper Information - Page 2 of 3. U.S. gas marketer. IGI acts as an agent for three LDC in seven states.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	5			
Term Bcf				
Term years				
Additional Information Poco will ship on Nova, on behalf of IGI.		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		Supply	
Type Gas sold by Poco to IGI will be delivered to InterMountain, WP Natural and Cascade Natural Gas.		**Type** Poco indicated it had supplied its data to the NEB.	
Location Pacific Northwest		**Location**	
Negotiations Evergreen provision. IGI has discretion of choosing delivery points on Northwest pipeline.		**Negotiations** Poco's contract is under a current gas removal permit.	
Volume 31 MMcf/d	**Term** 5 years	**Volume** 20 MMcf/d	**Term** (years)
Contract Signed Yes - WP Natural Gas Co.		**Contract Signed** Yes	
Regulatory Approval		**Comments on Supply** Poco indicated they have twice as much gas as required.	

PGT	Shipper IGI Resources, Inc.	Shipper Information - Page 3 of 3. U.S. gas marketer. IGI acts as an agent for three LDC in seven states.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	2.6			
Term Bcf	14.24			
Term years	15			
Additional Information Unigas will ship on Nova, on behalf of IGI.		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type Incremental.		**Type** Supply from its general gas supply pool.	
Location		**Location**	
Negotiations IGI is given the authority to purchase supplies for 100% of InterMountain's system on a long term basis.		**Negotiations**	
Volume (MMcf/d)	**Term** (years)	**Volume** 2.5 MMcf/d	**Term** (years)
Contract Signed Yes - InterMountain		**Contract Signed**	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	Shipper Norcen Marketing, Inc.	Shipper Information Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	48.5	47.02	47.49 47.74 *	
Term Bcf	265.77	522.84	260.01	
Term years	15	30	15	
Additional Information Norcen Energy Resources Limited will be the shipper on Nova and ANG.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** * As submitted by shipper.	

Market		**Supply**	
Type Various customers with no type provided.		**Type** Uncontracted gas production and supply pool.	
Location Northern California.		**Location** Norcen's own reserves exceed the 257 Bcf.	
Negotiations Customers have indicated a strong interest in long term gas supply agreements. Established marketing office in San Francisco.		**Negotiations** Dedicated 278 Bcf to the project.	
Volume (MMcf/d)	**Term** 15 years	**Volume** 47 MMcf/d	**Term** 15 years
Contract Signed No		**Contract Signed** No need	
Regulatory Approval		**Comments on Supply** Norcen's ongoing exploration will provide gas supply beyond the 30 year commitment to PGT.	

Appendix D: PGT Shipper Information

PGT	Shipper North Canadian Oils Limited	Shipper Information Canadian gas producer. See following page.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d		38.09	39.58	
Term Bcf		417.05	216.67	
Term years		30	15	
Additional Information North Canadian Marketing is an NCO affiliate. Information in this table was provided by PGT and ANG.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		Supply	
Type No information provided on market.		**Type**	
Location No information provided.		**Location**	
Negotiations		**Negotiations** No information provided.	
Volume MMcf/d	**Term** years	**Volume** MMcf/d	**Term** years
Contract Signed No information provided.		**Contract Signed** No information provided.	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	**Shipper** North Canadian Marketing Corporation	**Shipper Information** An affiliate of North Canadian Oils Limited.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	59.2	19.04	19.79	
Term Bcf		208.52	108.33	
Term years		30	15	
Additional Information North Canadian Marketing Corporation requested 59.2 MMcf/d for both NCO and NCMC		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		**Supply**	
Type No market type given.		**Type** Unable to supply information at this time.	
Location California		**Location**	
Negotiations No information provided.		**Negotiations** Uncertain	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed No		**Contract Signed** No	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	**Shipper** Northern California Power Agency	**Shipper Information** A Joint Powers Agency and Public Entity comprised of northern California utilities, intending to serve gas-fired electric generating facilities owned and operated by its members.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	5.6	5.33	5.54	
Term Bcf		58.39		
Term years		30		

Additional Information	**Contract** Yes Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.

Market		**Supply**	
Type Gas fired electric generating facilities owned by it's members.		**Type**	
Location Northern California utilities.		**Location**	
Negotiations No comment.		**Negotiations** In the process of securing gas supply.	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed They are the market.		**Contract Signed** No	
Regulatory Approval		**Comments on Supply** Indicated that final contracts would be approved in February 1992.	

Appendix D: PGT Shipper Information

PGT	**Shipper** Northridge Alberta Gas Sales Ltd.	**Shipper Information** Canadian gas marketer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d		7.84	8.15	
Term Bcf		85.85	44.60	
Term years		30	15	
Additional Information No submission.		**Contract** Yes	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type No information provided on market.		**Type**	
Location		**Location**	
Negotiations		**Negotiations** In the process of securing gas supply.	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed		**Contract Signed**	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

<table>
<tr><td>PGT</td><td>Shipper
Northwest Natural Gas Company</td><td colspan="3">Shipper Information - Page 1 of 3.
LDC serving Oregon and Washington.</td></tr>
<tr><td>Capacity</td><td>Nova</td><td>PGT Expansion</td><td>ANG Expansion</td><td>PG&E</td></tr>
<tr><td>MMcf/d</td><td>15.96 total</td><td>37.20 total
annual average *
11.00 annual **
4.516 winter **</td><td>38.18 total
annual average *
11.138 annual **
4.573 winter **</td><td></td></tr>
<tr><td>Term Bcf</td><td>87.41</td><td>145.11</td><td>73.46</td><td></td></tr>
<tr><td>Term years</td><td>15</td><td>30</td><td>15</td><td></td></tr>
<tr><td colspan="2">Additional Information
Poco will ship on Nova, on behalf of Northwest Natural. ANG's average annual volume was provided by ANG. It is an average of the winter volume of 46.43 MMcf/d and the summer volume of 29.92 MMcf/d.</td><td>Contract
Yes - Kingsgate to Stanfield</td><td colspan="2">Other Downstream Arrangements

Comments
Northwest pipeline expansion scheduled for April 1993 completion.
* Submitted by ANG.
** Submitted by shipper.</td></tr>
</table>

<table>
<tr><td colspan="2">Market</td><td colspan="2">Supply</td></tr>
<tr><td colspan="2">Type
Predominantly from the residential and commercial sectors and is, thus, sensitive to the cold weather.</td><td colspan="2">Type
Supply warranty.</td></tr>
<tr><td colspan="2">Location
Serving 320 000 residential, commercial, industrial, cogeneration and electric generation customers in Oregon and Washington.</td><td colspan="2">Location
Alberta</td></tr>
<tr><td colspan="2">Negotiations
No information provided.</td><td colspan="2">Negotiations
Complete</td></tr>
<tr><td>Volume (MMcf/d)</td><td>Term (years)</td><td>Volume 11.00 annual and 4.516 winter (MMcf/d)</td><td>Term 10 years</td></tr>
<tr><td colspan="2">Contract Signed</td><td colspan="2">Contract Signed Yes - 1 June 1991</td></tr>
<tr><td colspan="2">Regulatory Approval
Poco has an export application with the NEB and removal permit application with the ERCB.</td><td colspan="2">Comment on unit conversions.
At the delivery point assume 1000 Btu/cf, 1.2% shrinkage on PGT and 1.6% shrinkage on ANG.</td></tr>
</table>

PGT	Shipper Northwest Natural Gas Company	Shipper Information - Page 2 of 3. LDC serving Oregon and Washington.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	23.95	14.00 annual ** 9.275 winter **	14.176 annual ** 9.391 winter **	
Term Bcf	131.13	203.94	103.25	
Term years	15	30	15	
Additional Information Unigas will ship on Nova, on behalf of Northwest Natural. Northwest Expansion to deliver its ANG supplies from Stanfield to its distribution system.		**Contract**	**Other Downstream Arrangements** **Comments** Northwest pipeline expansion scheduled for April 1993 completion. ** Submitted by shipper.	

Market		Supply	
Type Predominantly from the residential and commercial sectors and is, thus, sensitive to the cold weather.		**Type** Supply warranty.	
Location Serving 320 000 residential, commercial, industrial, cogeneration and electric generation customers in Oregon and Washington.		**Location** Alberta	
Negotiations		**Negotiations** Complete	
Volume (MMcf/d)	**Term** (years)	**Volume** 14 annual and 9.275 winter (MMcf/d)	**Term** 10 years
Contract Signed		**Contract Signed** 1 June 1991 - annual 2 June 1991 - winter.	
Regulatory Approval Unigas is preparing to file export licence and removal permit applications.		**Comments on Supply** Unigas reserves information is in its submission, tab 10.	

PGT	**Shipper** Northwest Natural Gas Company	**Shipper Information - Page 3 of 3.** LDC serving Oregon and Washington.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	7.984	5.00 annual ** 2.758 winter **	5.063 annual ** 2.793 winter **	
Term Bcf	43.71	69.81	35.34	
Term years	15	30	15	
Additional Information Summit will ship on Nova, on behalf of Northwest Natural.		**Contract** Yes - Kingsgate to Stanfield	**Other Downstream Arrangements** **Comments** Northwest pipeline expansion scheduled for April 1993 completion. ** Submitted by shipper.	

Market		**Supply**	
Type Predominantly from the residential and commercial sectors and is thus sensitive to the cold weather.		**Type** Supply warranty.	
Location Serving 320 000 residential, commercial, industrial, cogeneration and electric generation in Oregon and Washington.		**Location** Alberta	
Negotiations		**Negotiations** Complete	
Volume (MMcf/d)	**Term** 7 years	**Volume** 5.00 annual and 2.758 winter MMcf/d	**Term** 7 years
Contract Signed		**Contract Signed** 1 June 1991	
Regulatory Approval Summit has filed an export application with the NEB and a removal permit application with the ERCB.		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	**Shipper** Pan Alberta Gas Ltd.	**Shipper Information** A Canadian gas aggregator and marketer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	60.3	57.91	59.36	
Term Bcf			650.01	
Term years			30	
Additional Information Some of this volume is not signed with Nova.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Executed transportation agreement with PG&E.	

Market		Supply	
Type Residential, commercial, industrial, electric cogeneration, IPP and other EOR. Representing incremental markets and will displace SW, US sources of supply.		**Type** Twenty four fields located throughout Alberta.	
Location Northern and Southern California		**Location** Details of volume, supply areas etc. are in Pan Alberta's original submission.	
Negotiations Negotiated a contract with Natural Gas Clearinghouse, a major US marketing entity.		**Negotiations** Has contracted or is in the final stages of contracting.	
Volume 58 MMcf/d	**Term** 19 years	**Volume** 113.1 MMcf/d	**Term** 15 years
Contract Signed Yes, minimum daily take of Natural Gas Clearinghouse; 60% of MDQ.		**Contract Signed** Close	

Comments on Supply
Pan Alberta's reserves summary currently has 443.5 Bcf of which 359 Bcf are forecast to be available 1 November 1993. Pan Alberta used GEMM (Gas Energy Management model) to look at the deliverability. Pan Alberta needs 76 MMcf/d for the first 15 years and 55.1 MMcf/d for the last 5 years, requiring, 516.5 MMcf/d for 20 years. Therefore plans are to add gas to the supply pool.

Appendix D: PGT Shipper Information

PGT	Shipper PanCanadian Petroleum Company	Shipper Information Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	41.39	39.74	40.74	
Term Bcf		446.09	223.05	
Term years		30	15	
Additional Information PanCanadian Petroleum Company will ship on Nova.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		Supply	
Type		**Type** PanCanadian corporate reserves pool.	
Location		**Location** 455 pools within 144 fields in Alberta for (552.8 Bcf).	
Negotiations Actively being negotiated.		**Negotiations**	
Volume MMcf/d	**Term** years	**Volume** MMcf/d	**Term** years
Contract Signed		**Contract Signed** No need.	
Regulatory Approval		**Comments on Supply** PanCanadian will enhance the supply pool through addition of fields and pools as necessary. More details are provided in PanCanadian's update.	

Appendix D: PGT Shipper Information

PGT	**Shipper** PanContinental Oil Ltd. (Inverness)	**Shipper Information** Inverness a Canadian gas producer, is the successor, in interest to PanContinental.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	4.2	3.92	4.07	
Term Bcf		42.93	22.31	
Term years		30	15	
Additional Information		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type Incremental market.		**Type** Uncontracted reserves in Alberta.	
Location California		**Location** Alberta	
Negotiations Presently working with a PGT shipper on carriage to their market.		**Negotiations**	
Volume 4.2 MMcf/d	**Term negotiating**	**Volume 4.2 MMcf/d**	**Term negotiating**
Contract Signed No		**Contract Signed** No	
Regulatory Approval		**Comments on Supply**	

Appendix D: PGT Shipper Information

PGT	**Shipper** Paramount Resources U.S., Inc.	**Shipper Information** Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	20.2	19.02	19.79	18.76
Term Bcf	110.60	208.27	108.33	205.37
Term years	15	30	15	30
Additional Information Paramount Resources Ltd. will ship on Nova and ANG.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** Start 1 Nov 1993 if PGT is ready. **Comments** Conversion factor used is 1 MMBtu = 1.03 MMcf.	

Market		**Supply**	
Type Electric power and gas utility.		**Type** Paramount corporate reserves pool.	
Location Southern California or northern California.		**Location** Alberta and Northwest Territories accessible to Nova (339 Bcf as of 31 December 1991).	
Negotiations Engaged in detailed discussions and anticipates contracts will be executed in the first half of 1992.		**Negotiations**	
Volume matching (MMcf/d)	**Term** target of 10 to 15 years	**Volume** matching (MMcf/d)	**Term** matching (years)
Contract Signed No		**Contract Signed** No need	
Regulatory Approval Application to be filed when contracts are signed.		**Comments on Supply** Intends to provide gas supply from pools that are dedicated to it's corporate role.	

PGT	Shipper Petro-Canada Hydrocarbons, Inc.	Shipper Information Canadian gas producer.		
Capacity	Nova	PGT Expansion	ANG Expansion	PG&E
MMcf/d	20.2	19.04	19.79	
Term Bcf		208.52	108.33	
Term years		30	15	
Additional Information		Contract Yes - Kingsgate to Malin	Other Downstream Arrangements Comments Establishing transportation agreement with PG&E.	

Market		Supply	
Type Gas marketing company.		Type PetroCanada corporate reserves pool.	
Location California		Location	
Negotiations Indicated it had established a gas sales agreement with GASMARK Inc.		Negotiations	
Volume (MMcf/d)	Term (years)	Volume (MMcf/d)	Term (years)
Contract Signed Yes		Contract Signed No need	
Regulatory Approval		Comments on Supply Presently realigning its total natural gas reserves. This is a function of asset sales, purchases, etc. They did not wish to submit any further information to this proceeding.	

Appendix D: PGT Shipper Information

PGT	**Shipper** Sacramento Municipal Utility District	**Shipper Information** A municipal electric utility serving the greater Sacramento area.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	12.5	11.67	12.22	
Term Bcf		127.82	133.82	
Term years		30	30	
Additional Information Some of the Nova volume is not signed with Nova.		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		**Supply**	
Type Gas fired electric generating facilities. SMUD is a municipal electric utility.		**Type**	
Location Sacramento area in Northern California.		**Location**	
Negotiations		**Negotiations** Currently, contracts are not finalized.	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed N/A SMUD is the market.		**Contract Signed** No	
Regulatory Approval		**Comments on Supply** Expects to proceed with fuel procurement over the next several months.	

PGT	**Shipper** Salmon Resources Limited	**Shipper Information** A wholly owned Shell subsidiary.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	28.15	27.70	27.70	27
Term Bcf		303.32		
Term years		30		

Additional Information Shell requested the Nova volume (Salmon is its subsidiary). Shell's total Nova requirement for sales to Edison and Salmon is 80 MMcf/d.	**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Capacities given are at the inlet of each pipeline.

Market		**Supply**	
Type		**Type** Shell intends to use existing company supply.	
Location California.		**Location**	
Negotiations Negotiating gas sales arrangements with markets in California.		**Negotiations**	
Volume MMcf/d	**Term** years	**Volume** MMcf/d	**Term** years
Contract Signed No		**Contract Signed** No need	
Regulatory Approval		**Comments on Supply**	

PGT	**Shipper** San Diego Gas & Electric Company	**Shipper Information - Page 1 of 4.** Utility electric generation company.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d MMBtu/d	54 total of pages 1 to 4	51.04 total of pages 1 to 4 52 508	53.03 total of pages 1 to 4 53 300	50 total of pages 1 to 4 51 800
Term Bcf		558.89	290.34	
Term years		30	15	30
Additional Information Husky Oil Supply		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type System supply.		**Type** Alberta corporate reserves pool.	
Location Southern California - San Diego and environs.		**Location** While there is no specific dedication of corporate reserves, it is expected that the SDG&E contract will be served from Husky's working interest share of the Caroline and Karr gas fields of Alberta.	
Negotiations N/A - SDG&E is the market.		**Negotiations** None required.	
Volume N/A	**Term** N/A	**Volume** 25 MMcf/d	**Term** 10 years
Contract Signed N/A - SDG&E is the market.		**Contract Signed** Yes	
Regulatory Approval All (Bow Valley, Canadian Hunter, Husky and Summit) have filed export applications with the NEB. Summit has filed a removal permit application with the ERCB. Husky and Bow Valley will file with the ERCB shortly and Canadian Hunter will file with B.C.		**Comments on Supply** Sufficient supply to meet contractual commitments. Deliverability will be supplemented, if required.	

PGT	Shipper San Diego Gas & Electric Company	Shipper Information - Page 2 of 4. Utility electric generation company.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d				
Term Bcf				
Term years				
Additional Information Canadian Hunter Supply		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type System supply.		**Type** B.C. corporate reserves pool.	
Location Southern California - San Diego and environs.		**Location** While there is no specific dedication of corporate reserves, it is expected that the SDG&E contract will be served from the Border Montney field. The field is unitized and straddles the Alberta/ B.C. border. Canadian Hunter will serve the SDG&E contract from reserves on the B.C. side (Border Montney Unit B).	
Negotiations N/A - SDG&E is the market.		**Negotiations** None required.	
Volume N/A	**Term** N/A	**Volume** 20 MMcf/d	**Term** 10 years
Contract Signed N/A - SDG&E is the market.		**Contract Signed** Yes	
Regulatory Approval All (Bow Valley, Canadian Hunter, Husky and Summit) have filed export applications with the NEB. Summit has filed a removal permit application with the ERCB. Husky and Bow Valley will file with the ERCB shortly and Canadian Hunter will file with B.C.		**Comments on Supply** Sufficient supply from proven developed and undeveloped reserves to meet contractual commitments. Reserves will be developed as required and deliverability will be supplemented, if required.	

PGT	Shipper San Diego Gas & Electric Company	Shipper Information - Page 3 of 4. Utility electric generation company.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d				
Term Bcf				
Term years				
Additional Information Bow Valley Industries Supply		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type System supply.		**Type** Alberta corporate reserves pool.	
Location Southern California - San Diego and environs.		**Location** The SDG&E contract will be served from Bow Valley's interests in gas fields in Alberta.	
Negotiations N/A - SDG&E is the market.		**Negotiations** None required.	
Volume N/A	**Term** N/A	**Volume** 5 MMcf/d	**Term** 11 years
Contract Signed N/A - SDG&E is the market.		**Contract Signed** Yes	
Regulatory Approval All (Bow Valley, Canadian Hunter, Husky and Summit) have filed export applications with the NEB. Summit has filed a removal permit application with the ERCB. Husky and Bow Valley will file with the ERCB shortly and Canadian Hunter will file with B.C.		**Comments on Supply** Sufficient supply to meet contractual commitments. Deliverability will be supplemented, if required.	

PGT	**Shipper** San Diego Gas & Electric Company	**Shipper Information - Page 4 of 4.** Utility electric generation company.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d				
Term Bcf				
Term years				
Additional Information Summit Resources Supply		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type System supply.		**Type** Alberta corporate reserves pool.	
Location Southern California - San Diego and environs.		**Location** While there is no specific dedication of corporate reserves, it is expected that the SDG&E contract will be served from Summit's interests in the following Alberta areas: Boundary Lake, Chain Lake, Craigmyle, Gilby, Jeffrey and Turin.	
Negotiations N/A - SDG&E is the market.		**Negotiations** None required.	
Volume N/A	**Term** N/A	**Volume** 7 MMcf/d	**Term** 8 years
Contract Signed N/A - SDG&E is the market.		**Contract Signed** Yes	
Regulatory Approval All (Bow Valley, Canadian Hunter, Husky and Summit) have filed export applications with the NEB. Summit has filed a removal permit application with the ERCB. Husky and Bow Valley will file with the ERCB shortly and Canadian Hunter will file with B.C.		**Comments on Supply** Sufficient supply to meet contractual commitments. Deliverability will be supplemented, if required.	

<table>
<tr><td rowspan="1">PGT</td><td>Shipper
Southern California Edison
AEC</td><td colspan="3">Shipper Information - Page 1 of 4.
Second largest electrical utility operating in the U.S.</td></tr>
<tr><td>Capacity</td><td>Nova</td><td>PGT Expansion</td><td>ANG Expansion</td><td>PG&E</td></tr>
<tr><td>MMcf/d

MMBtu/d</td><td>52</td><td>196.03 total of pages 1 to 4
201 687</td><td>203.69 total of pages 1 to 4
203 694</td><td>

198 863</td></tr>
<tr><td>Term Bcf</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Term years</td><td>15</td><td>30</td><td>15</td><td>30</td></tr>
<tr><td colspan="2">Additional Information
AEC on behalf of Edison</td><td>Contract
Yes - Kingsgate to Malin</td><td colspan="2">Other Downstream Arrangements

Comments</td></tr>
</table>

<table>
<tr><td colspan="2">Market</td><td colspan="2">Supply</td></tr>
<tr><td colspan="2">Type
Edison is the second largest electrical utility, in the U.S., operating in central and southern California.</td><td colspan="2">Type
AEC current reserves or from Pan Alberta or from reserves in Suffield after those contracts expire.</td></tr>
<tr><td colspan="2">Location
Central and southern California.</td><td colspan="2">Location
Alberta</td></tr>
<tr><td colspan="2">Negotiations
No need for negotiations.</td><td colspan="2">Negotiations
Complete.</td></tr>
<tr><td>Volume 52.3 MMcf/d</td><td>Term 15 years</td><td>Volume 52.3 MMcf/d</td><td>Term 15 years</td></tr>
<tr><td colspan="2">Contract Signed
N/A Edison is the market.</td><td colspan="2">Contract Signed
Yes</td></tr>
<tr><td colspan="2">Regulatory Approval
Edison/AEC have filed jointly for export licences with the NEB and have filed a removal permit application with the ERCB in May 1992.</td><td colspan="2">Comments on Supply
AEC has entered into an agreement with Pan Alberta to satisfy 40% of contracted volumes with Edison.</td></tr>
</table>

<table>
<tr><td colspan="2">PGT</td><td colspan="2">Shipper
Southern California Edison Esso</td><td colspan="3">Shipper Information - Page 2 of 4.
Second largest electrical utility operating in the U.S.</td></tr>
<tr><td colspan="2">Capacity</td><td colspan="2">Nova</td><td>PGT Expansion</td><td>ANG Expansion</td><td>PG&E</td></tr>
<tr><td colspan="2">MMcf/d</td><td colspan="2">52</td><td></td><td></td><td></td></tr>
<tr><td colspan="2">Term Bcf</td><td colspan="2"></td><td></td><td></td><td></td></tr>
<tr><td colspan="2">Term years</td><td colspan="2"></td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Additional Information
Esso on behalf of Edison</td><td>Contract
Yes - Kingsgate to Malin</td><td colspan="2">Other Downstream Arrangements

Comments</td></tr>
</table>

Market		**Supply**	
Type Edison is the second largest electrical utility, in the U.S., operating in central and southern California.		**Type** Corporate reserves pool.	
Location Central and southern California.		**Location** Alberta	
Negotiations No need for negotiations.		**Negotiations** Complete.	
Volume 52.3 MMcf/d	**Term** 15 years	**Volume** 52.3 MMcf/d	**Term** 15 years
Contract Signed N/A Edison is the market.		**Contract Signed** Yes	
Regulatory Approval Edison/Esso have filed jointly for export licences with the NEB and have filed a removal permit application with the ERCB.		**Comments on Supply** Details of reserves were submitted in the ERCB call for information. The corporate reserves pool is sufficient with a surplus of 275 Bcf.	

PGT	**Shipper** Southern California Edison Shell	**Shipper Information - Page 3 of 4.** Second largest electrical utility operating in the U.S.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	52			
Term Bcf				
Term years				

Additional Information Shell on behalf of Edison	**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments**

Market		**Supply**	
Type Edison is the second largest electrical utility, in the U.S., operating in central and southern California.		**Type** Specific pools.	
Location Central and southern California.		**Location** Alberta fields: Caroline,Hamburg, Panther, Progress, Clearwater, S. Hamburg, etc.	
Negotiations No need for negotiations.		**Negotiations** Complete.	
Volume 52 MMcf/d	**Term** 15 years	**Volume** 52 MMcf/d	**Term** 15 years
Contract Signed N/A Edison is the market.		**Contract Signed** Yes	
Regulatory Approval Edison/Shell filed jointly for export licences with the NEB and have filed a removal permit application with the ERCB.		**Comments on Supply** Details of reserves were submitted in the ERCB call for information. Shell indicated it had sufficient reserves for Edison and Salmon. These should be checked against corporate reserve pool.	

PGT	**Shipper** Southern California Edison WGML	**Shipper Information - Page 4 of 4.** Second largest electrical utility operating in the U.S.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	52			
Term Bcf				
Term years				
Additional Information WGML on behalf of Edison		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type Edison is the second largest electrical utility, in the U.S., operating in central and southern California.		**Type** Operates the single largest supply pool in North America.	
Location Central and southern California.		**Location** Alberta	
Negotiations No need for negotiations.		**Negotiations** Complete.	
Volume 52.3 MMcf/d	**Term** 15 years	**Volume** 52.3 MMcf/d	**Term** 15 years
Contract Signed N/A Edison is the market.		**Contract Signed** Yes	
Regulatory Approval Edison/WGML have filed jointly for export licences with the NEB and have filed a removal permit application with the ERCB.		**Comments on Supply** Details of reserves were submitted in the ERCB call for information. WGML indicated that it had remaining reserves totalling 17.8 Tcf. WGML indicated it has sufficient reserves to meet all of its contracted gas requirements.	

PGT	Shipper Suncor Inc.	Shipper Information Canadian gas producer.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d MMBtu/d	41.6	39.23 40 361	40.76	38.64 39 379
Term Bcf		429.56	223.16	
Term years	15	30	15	30
Additional Information		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments** Establishing transportation agreement with PG&E.	

Market		Supply	
Type		**Type** Suncor's corporate supply pool.	
Location California.		**Location**	
Negotiations Intends to market in California and is establishing arrangements with markets.		**Negotiations** Indicted it had 178 Bcf and only needs 29 Bcf.	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed No		**Contract Signed** No need	
Regulatory Approval		**Comments on Supply** Supplied more data on 13 February 1992. Indicated it had established reserves of 210 Bcf with an ultimate potential of 256 Bcf.	

Appendix D: PGT Shipper Information

PGT	Shipper Vector Energy, Inc.	Shipper Information Marketer of natural gas from BC.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	17.2	16.71	16.87	Yes
Term Bcf	94.17	182.97	93.84	
Term years	15	30	17	30
Additional Information		**Contract** Yes - Kingsgate to Malin	**Other Downstream Arrangements** **Comments**	

Market		Supply	
Type Long and short term markets for industrial, utility electric generation and cogeneration.		**Type** Hondo, Marten Hills and Rock Island	
Location Northern and southern California.		**Location** Alberta (36 Bcf).	
Negotiations End-use markets not finalized; expected to be complete by the end of June 1992.		**Negotiations** Close to signing with Ulster Petroleum Ltd.; details of the contract were provided.	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed No		**Contract Signed** No	
Regulatory Approval		**Comments on Supply** Ulster plans to add an additional 60 Bcf with further exploration expenditures.	

PGT	Shipper Washington Energy Exploration, Inc.	Shipper Information - Page 1 of 2. LDC company serving Puget Sound.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	66.6 total	19.04	55.04 total of pages 1 to 2	Yes
Term Bcf		208.49	301.34	
Term years		30	15	

Additional Information	**Contract**	**Other Downstream Arrangements**
ANG's average annual volume is an average of 65.356 MMcf/d (winter) and 44.723 MMcf/d (summer).	Yes - Kingsgate to Malin	**Comments** Indicated contracts have been executed.

Market		**Supply**	
Type Presently utility and non-core. Pursuing proposed cogeneration. Winter gas will be for residential use.		**Type** Four gas aggregators.	
Location Pacific Northwest and California.		**Location** Alberta	
Negotiations Presently a gas supplier. Looking for LDC markets in the Pacific NW as well.They have also established a marketing office in Long Beach California. Expect to sign in summer.		**Negotiations**	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed		**Contract Signed** No	
Regulatory Approval		**Comments on Supply** Will complete negotiations after market is more firm.	

Appendix D: PGT Shipper Information

PGT	Shipper Washington Energy Exploration, Inc.	Shipper Information - Page 2 of 2. LDC company serving Puget Sound.		
Capacity	Nova	PGT Expansion	ANG Expansion	PG&E
MMcf/d		34.35		
Term Bcf		486.24		
Term years		30	15	
Additional Information		Contract Yes - Kingsgate to Stanfield	Other Downstream Arrangements Comments	

Market		Supply	
Type		Type Four gas aggregators.	
Location		Location Alberta	
Negotiations Presently a gas supplier. Looking for LDC markets in the Pacific NW as well.They have also established a marketing office in Long Beach California. Expect to sign in the summer.		Negotiations Received supply proposals.	
Volume (MMcf/d)	Term (years)	Volume (MMcf/d)	Term (years)
Contract Signed		Contract Signed	
Regulatory Approval		Comments on Supply Will complete negotiations after market is more firm.	

Appendix D: PGT Shipper Information

PGT	Shipper Washington Water Power Company	Shipper Information - Page 1 of 3.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	10	41.23 total of pages 1 to 3	42.11 total of pages 1 to 3	
Term Bcf		451.44	461.10	
Term years		30	30	
Additional Information AEC will ship on Nova, on behalf of WP. The ANG average annual volume is an average of the 54.432 MMcf/d (winter) and 29.785 MMcf/d (summer) volumes.		**Contract** Yes - Kingsgate to Idaho and Washington	**Other Downstream Arrangements** AEC will sell to WWPC. **Comments**	

Market		**Supply**	
Type Information provided in the Grand Valley submission.		**Type** Amerada Hess.	
Location		**Location** Alberta	
Negotiations		**Negotiations** Complete	
Volume (MMcf/d)	**Term** (years)	**Volume** 10 to 16 MMcf/d	**Term** 7 years
Contract Signed Yes		**Contract Signed** Yes	
Regulatory Approval AEC and Pan Canadian have, with Grand Valley as their agent, filed export applications with the NEB.		**Comments on Supply** 11 Bcf of currently proven producing undedicated reserves.	

Appendix D: PGT Shipper Information

PGT	**Shipper** Washington Water Power Company	**Shipper Information - Page 2 of 3.**		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	9.94			
Term Bcf				
Term years			30	
Additional Information Pan Canadian will ship on Nova, on behalf of WP.		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type		**Type** Pan Canadian corporate reserves pool.	
Location		**Location** 455 pools within 144 fields in Alberta for (552.8 Bcf).	
Negotiations Washington Water Power which will use its own transportation capacity on PGT from Alberta to Spokane.		**Negotiations** Complete	
Volume 10 MMcf/d Initial 53 Bcf	**Term** 10 years	**Volume** (MMcf/d)	**Term** (years)
Contract Signed Yes, renewal option for 5 years. Increasing by 1 MMcf/d per year to a total of 19 MMcf/d. Minimum annual take of 70% of daily quantity.		**Contract Signed** Yes	
Regulatory Approval		**Comments on Supply** Pan Canadian will enhance the supply pool through addition of fields and pools as necessary. More details are provided in Pan Canadian's update.	

PGT	**Shipper** Washington Water Power Company	**Shipper Information - Page 3 of 3.**		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d	36.3			
Term Bcf				
Term years				
Additional Information		**Contract**	**Other Downstream Arrangements** **Comments**	

Market		**Supply**	
Type		**Type** AEC and Grand Valley Gas (acting as agent for WWP and WP National).	
Location		**Location** Alberta	
Negotiations		**Negotiations** Complete	
Volume (MMcf/d)	**Term** (years)	**Volume** 10 to 20 MMcf/d	**Term** 10 years
Contract Signed		**Contract Signed** Yes	
Regulatory Approval		**Comments on Supply** Reserves will come from AEC working interest or be purchased from Pan Alberta. AEC has entered into a contract with Pan Alberta to supply 40 % of contracted reserves to AEC.	

Appendix D: PGT Shipper Information

PGT	**Shipper** WP Natural Gas (formerly CP National Corporation)	**Shipper Information** LDC company serving Oregon and California. Washington Water power purchased certain assets of CP National.		
Capacity	**Nova**	**PGT Expansion**	**ANG Expansion**	**PG&E**
MMcf/d		3.22	3.34	
Term Bcf		193.03		
Term years		30		
Additional Information See Washington Water Power Company and AEC. Some of the Washington Water power volume is not signed with Nova. The ANG annual average volume is 3.34 MMcf/d with a winter volume of 6.686 MMcf/d.		**Contract** Yes - Kingsgate to Oregon	**Other Downstream Arrangements** Contracting for additional firm service on the proposed expansion of Northwest's system. **Comments**	

Market		**Supply**	
Type WP is a LDC serving approximately 70 000 customers in Oregon and California.		**Type** AEC, Amerada Hess Canada Ltd., and Pan Canadian Petroleum Limited gas.	
Location Oregon		**Location** Alberta...see Washington Water Power data.	
Negotiations Washington Water Power has purchased certain gas assets of CP National. Grand Valley Gas, is acting agent for both WWP and WP Natural Gas.		**Negotiations**	
Volume (MMcf/d)	**Term** (years)	**Volume** (MMcf/d)	**Term** (years)
Contract Signed		**Contract Signed** Yes	
Regulatory Approval		**Comments on Supply**	

<table>
<tr><td>PGT SUMMARY</td><td>Shipper
Total</td><td colspan="3">Shipper Final Page - Page 1 of 2.</td></tr>
<tr><td>Capacity</td><td>Nova</td><td>PGT Expansion</td><td>ANG Expansion</td><td>PG&E</td></tr>
<tr><td>MMcf/d</td><td>913.55 total submitted by shippers</td><td>904.96 total submitted by both PGT (table i-2 and i-3 of initial submission) and shippers who made changes</td><td>877.512 annual average at Kingsgate 915.504 maximum volume at Kingsgate*</td><td></td></tr>
<tr><td>MMcf/d</td><td>829.4
Nova submission</td><td>877.6 total submitted by PGT in its final submission</td><td>930.152
at A/BC border</td><td></td></tr>
<tr><td colspan="2">Additional Information
There is a difference between the volumes signed on Nova and ANG. The difference was identified as 100 MMcf/d during the oral proceeding. This relates to the difference between 930 MMcf/d at the A/BC border and the volume submitted by Nova. The following are the volumes: Sacremento 12.4 MMcf/d, WWP 26 MMcf/d, BC Gas 5 MMCf/d and Pan Alberta 60 MMcf/d that account for the difference.</td><td>Conversions
PGT submitted its volumes in MMBtu/d. These were converted to MMcf/d with PGT's conversion factor. See the following table D49 and D50.</td><td colspan="2">Other Downstream Arrangements

Comments
* Note that all ANG volumes are as submitted by ANG unless otherwise stated.</td></tr>
</table>

Market	**Supply**
Type Various types.	**Type** Many shippers have identified reserves coming from corporate reserve pools. Others have indicated they will add additional supply by future drilling and acquiring reserves from other producers.
Location The target market is California with a split between northern and southern California.	**Location** Alberta, mainly, but also from B.C. and Saskatchewan.

<table>
<tr><td colspan="2">Altamont Summary Continued.......

Negotiations
While negotiations are under way for many of the PGT shippers, there are 13 signed contracts for end-use markets. Not all of these are signed for terms that are as long as the transportation agreements.</td><td colspan="2">Page 2 of 2.

Negotiations</td></tr>
<tr><td>Volume (MMcf/d)
PGT indicated in its final submission that its end-use market was 413.9 MMcf/d with 458.7 remaining. Of the 458.7 MMcf/d, 91.3 MMcf/d was signed and 367.4 MMcf/d was under negotiation.</td><td>Term (years)</td><td>Volume (MMcf/d)</td><td>Term (years)</td></tr>
<tr><td colspan="2">Contract Signed

ERCB review of this Appendix:
448.55 MMcf/d signed and
207.87 MMcf/d under negotiation.
The ERCB did not assume negotiation unless the shipper indicated that to be the case.</td><td colspan="2">Contract Signed
One half of the shippers have firm supply signed. Others are in the midst of negotiation.</td></tr>
<tr><td colspan="2">Regulatory Approval
A few of the shippers have already filed applications with the NEB and the ERCB for gas removal.</td><td colspan="2">Comments on Supply</td></tr>
</table>

Appendix D: PGT

	PGT	Capacity		Capacity		Capacity		Capacity						Transportation
	Shipper	Daily		Winter		Summer		Annual	Term	Daily	Annual	Term	Term	Contract
		MMBtu/d	MMcf/d	MMbtu/d	MMcf/d	MMbtu/d	MMcf/d	Bcf	Bcf	E6m3/d	E6m3	E9m3	years	Signed
1	BC Gas Inc.													
2	BP Resources Canada Limited	10250	9.96					3.64	58.18	0.28	102.45	1.64	16	Yes - Stanfield to Malin
3	Canwest Gas Supply Inc.	15708	15.27					5.57	89.16	0.43	157.00	2.51	16	Yes - Stanfield to Malin
	Canwest Gas Supply USA, Inc.	27429	26.66					9.73	291.93	0.75	274.16	8.22	30	Yes - Kingsgate to Malin
	Canwest Gas Supply USA, Inc.	35000	34.02					12.42	372.50	0.96	349.83	10.49	30	Yes - Stanfield to Malin
4	Cascade Natural Gas Corporation	3725	3.62	7456	7.25			1.32	39.68	0.10	37.26	1.12	30	Yes - Kingsgate to Oregon
5	Chevron U.S.A., Inc.	31348	30.47					11.12	333.64	0.86	313.33	9.40	30	Yes - Kingsgate to Malin
	Chevron U.S.A., Inc.	20000	19.44	20000	19.44	20000	19.44	7.10	212.86	0.55	199.90	6.00	30	Yes - Kingsgate to Stanfield
6	City of Burbank	4770	4.82					1.76	52.78	0.14	49.57	1.49	30	Yes - Kingsgate to Malin
7	City of Glendale	4034	3.97					1.45	43.47	0.11	40.83	1.22	30	Yes - Kingsgate to Malin
8	City of Pasadena	4034	3.97					1.45	43.47	0.11	40.83	1.22	30	Yes - Kingsgate to Malin
9	Dekalb Energy Company Ltd.	11755	11.43					4.17	125.11	0.32	117.49	3.52	30	Yes - Kingsgate to Malin
10	IGI Resources, Inc.	7158	6.96					2.54	76.18	0.20	71.55	2.15	30	Yes - Kingsgate to Stanfield
	IGI Resources, Inc.													Yes - Kingsgate to Stanfield
	IGI Resources, Inc.													Yes - Kingsgate to Stanfield
11	Norcen Marketing, Inc.	47022	47.02					17.16	522.84	1.32	483.55	14.51	30	Yes - Kingsgate to Malin
12	North Canadian Oils Limited	39185	38.09					13.90	417.05	1.07	391.66	11.75	30	Yes - Kingsgate to Malin
13	North Canadian Marketing Corp.	19592	19.04					6.95	208.52	0.54	195.83	5.87	30	Yes - Kingsgate to Malin
14	Northern California Power Agency	5486	5.33					1.95	58.39	0.15	54.83	1.65	30	Yes Kingsgate to Malin
15	Northridge Alberta Gas Sales Ltd.	8066	7.84					2.86	85.85	0.22	80.62	2.42	30	Yes
16	Northwest Natural Gas Company	38275	37.20	46549	45.24	30000	29.16	10.64	319.29	0.82	299.86	9.00	30	Yes - Kingsgate to Stanfield
	Northwest Natural Gas Company													Yes - Kingsgate to Stanfield
	Northwest Natural Gas Company													Yes - Kingsgate to Stanfield
17	Pan Alberta Gas Ltd.	58777	57.91					21.14		1.63	595.52			Yes - Kingsgate to Malin
18	PanCanadian Petroleum Company	40338	39.74					14.51	435.15	1.12	408.67	12.26	30	Yes - Kingsgate to Malin
19	PanContinental Oil Ltd. (Inverness)	4034	3.92					1.43	42.93	0.11	40.32	1.21	30	Yes - Kingsgate to Malin
20	Paramount Resources U.S., Inc.	19596	19.02					6.94	208.27	0.54	195.59	5.87	30	Yes - Kingsgate to Malin
21	Petro-Canada Hydrocarbons, Inc.	19592	19.04					6.95	208.52	0.54	195.83	5.87	30	Yes - Kingsgate to Malin
22	Sacramento Municipal Utility District	12010	11.67					4.26	127.82	0.33	120.04	3.60	30	Yes - Kingsgate to Malin
23	Salmon Resources Limited	27429	27.70					10.11	303.32	0.78	284.85	8.55	30	Yes - Kingsgate to Malin
24	San Diego Gas & Electric Company	52508	51.04					18.63	558.89	1.44	524.87	15.75	30	Yes - Kingsgate to Malin
	San Diego Gas & Electric Company													Yes - Kingsgate to Malin
	San Diego Gas & Electric Company													Yes - Kingsgate to Malin
	San Diego Gas & Electric Company													Yes - Kingsgate to Malin
25	Southern California Edison AEC	201687	196.03					71.55	2146.55	5.52	2015.90	60.48	30	Yes - Kingsgate to Malin
	Southern California Edison Esso													Yes - Kingsgate to Malin
	Southern California Edison Shell													Yes - Kingsgate to Malin
	Southern California Edison WGML													Yes - Kingsgate to Malin
26	Suncor Inc.	40361	39.23					14.32	429.56	1.11	403.42	12.10	30	Yes - Kingsgate to Malin
27	Vector Energy, Inc.	16707	16.71					6.10	182.97	0.47	171.84	5.16	30	Yes - Kingsgate to Malin
28	Washington Energy Exploration, Inc.	19592	19.04					6.95	208.52	0.54	195.83	5.87	30	Yes - Kingsgate to Malin
	Washington Energy Exploration, Inc.	35343	34.35	45686	44.41	25000	24.30	12.54	376.20	0.97	353.26	10.60	30	Yes - Kingsgate to Stanfield
29	Washington Water Power Company	42417	41.23	51582	50.14	30000	29.16	15.05	451.44	1.16	423.97	12.72	30	Yes - Kingsgate to Pacific NW
	Washington Water Power Company													Yes - Kingsgate to Pacific NW
	Washington Water Power Company													Yes - Kingsgate to Pacific NW
30	WP Natural Gas (formerly CP)	3310	3.22	6620	6.43			1.17	193.03	0.09	33.08	0.99	30	Yes - Kingsgate to Oregon
	Total	926538	904.96	177893	172.91	105000	102.06	327.38	9224.07	25.27	9223.52	255.21		

Appendix D: PGT

	PGT	Transportation	Nova Name	Nova		ANG			PG&E
	Shipper	Contract		Daily	Daily	Kingsgate	Kingsgate	A/BC	Daily
		Signed		MMcf/d	E6m3/d	MMcf/d (avg)	E6m3/d	MMcf/d (max)	MMcf/d
1	BC Gas Inc.		Not shipping on Nova as this is BC gas.			5.00	0.14	5.08	
2	BP Resources Canada Limited	Yes - Stanfield to Malin	BP Resources Canada Limited						
3	Canwest Gas Supply Inc.	Yes - Stanfield to Malin	Canwest Gas Supply Inc.	28.3	0.80	27.70	0.78	28.15	
	Canwest Gas Supply USA, Inc.	Yes - Kingsgate to Malin							
	Canwest Gas Supply USA, Inc.	Yes - Stanfield to Malin							
4	Cascade Natural Gas Corporation	Yes - Kingsgate to Oregon	See IGI.			3.75	0.21	7.61	
5	Chevron U.S.A., Inc.	Yes - Kingsgate to Malin	Chevron Canada Resources	53.1	1.50	52.00	1.47	52.83	
	Chevron U.S.A., Inc.	Yes - Kingsgate to Stanfield	Chevron Canada Resources						
6	City of Burbank	Yes - Kingsgate to Malin	Unigas will be the shipper on Nova.	4.91	0.14	4.82	0.14	4.89	4.66
7	City of Glendale	Yes - Kingsgate to Malin	Unigas will be the shipper on Nova.	4.2	0.12	4.07	0.12	4.14	3.92
8	City of Pasadena	Yes - Kingsgate to Malin	Unigas will be the shipper on Nova.	4.2	0.12	4.07	0.12	4.14	3.92
9	Dekalb Energy Company Ltd.	Yes - Kingsgate to Malin	Dekalb Energy Canada	12.1	0.34	11.87	0.34	12.06	
10	IGI Resources, Inc.	Yes - Kingsgate to Stanfield	Grand Valley Gas Company on behalf of IGI.	7.3	0.21	7.00	0.20	7.11	
	IGI Resources, Inc.	Yes - Kingsgate to Stanfield	Poco will ship on Nova, on behalf of IGI.	5	0.14				
	IGI Resources, Inc.	Yes - Kingsgate to Stanfield	Unigas will ship on Nova, on behalf of IGI.	2.6	0.07				
11	Norcen Marketing, Inc.	Yes - Kingsgate to Malin	Norcen Energy Resources Limited	48.5	1.37	47.49	1.35	48.25	
12	North Canadian Oils Limited	Yes - Kingsgate to Malin				39.58	1.22	40.21	
13	North Canadian Marketing Corporatio	Yes - Kingsgate to Malin	NCMO requested for both NCO and NCMC.	59.2	1.67	19.79	0.56	20.10	
14	Northern California Power Agency	Yes Kingsgate to Malin		5.6	0.16	5.54	0.16	5.63	
15	Northridge Alberta Gas Sales Ltd.	Yes				8.15	0.23	8.28	
16	Northwest Natural Gas Company	Yes - Kingsgate to Stanfield	Poco on behalf of Northwest Natural.	15.966	0.45	38.18	1.32	47.17	
	Northwest Natural Gas Company	Yes - Kingsgate to Stanfield	Unigas on behalf of Northwest Natural.	23.95	0.67		0.85		
	Northwest Natural Gas Company	Yes - Kingsgate to Stanfield	Summit on behalf of Northwest Natural.	7.984	0.22				
17	Pan Alberta Gas Ltd.	Yes - Kingsgate to Malin	Some of this volume is not signed with Nova.	60.3	1.70	59.36	1.68	60.31	
18	PanCanadian Petroleum Company	Yes - Kingsgate to Malin	PanCanadian Petroleum Company	41.39	1.17	40.74	1.15	41.39	
19	PanContinental Oil Ltd. (Inverness)	Yes - Kingsgate to Malin		4.2	0.12	4.07	0.12	4.14	
20	Paramount Resources U.S., Inc.	Yes - Kingsgate to Malin	Paramount Resources Ltd.	20.2	0.57	19.79		20.10	18.76
21	Petro-Canada Hydrocarbons, Inc.	Yes - Kingsgate to Malin		20.2	0.57	19.79	0.56	20.10	
22	Sacramento Municipal Utility District	Yes - Kingsgate to Malin	Some of the Nova volume is not signed.	12.5	0.35	12.22	0.35	12.42	
23	Salmon Resources Limited	Yes - Kingsgate to Malin	Shell requested the Nova volume.	28.15	0.79	27.70	0.78	28.15	27
24	San Diego Gas & Electric Company	Yes - Kingsgate to Malin	Husky Oil supply.	54	1.52	53.03	1.50	53.88	50
	San Diego Gas & Electric Company	Yes - Kingsgate to Malin	Canadian Hunter supply.						
	San Diego Gas & Electric Company	Yes - Kingsgate to Malin	Bow Valley Industries supply.						
	San Diego Gas & Electric Company	Yes - Kingsgate to Malin	Summit Resources suuply.						
25	Southern California Edison AEC	Yes - Kingsgate to Malin	AEC on behalf of Edison.	52	1.47	203.69	5.77	206.95	193.07
	Southern California Edison Esso	Yes - Kingsgate to Malin	Esso on behalf of Edison.	52	1.47				
	Southern California Edison Shell	Yes - Kingsgate to Malin	Shell on behalf of Edison.	52	1.47		0.78		
	Southern California Edison WGML	Yes - Kingsgate to Malin	WGML on behalf of Edison.	52	1.47				
26	Suncor Inc.	Yes - Kingsgate to Malin	Suncor Inc.	41.6	1.17	40.76	1.15	41.42	38.64
27	Vector Energy, Inc.	Yes - Kingsgate to Malin		17.2	0.48	16.87	0.48	17.14	Yes
28	Washington Energy Exploration, Inc.	Yes - Kingsgate to Malin		66.6	1.88	55.04	1.85	66.40	Yes
	Washington Energy Exploration, Inc.	Yes - Kingsgate to Stanfield					1.27		
29	Washington Water Power Company	Yes - Kingsgate to Pacific NW	AEC will ship on Nova, on behalf of WP.	10	0.28	42.11	1.54	55.30	
	Washington Water Power Company	Yes - Kingsgate to Pacific NW	Pan Canadian, on behalf of WP.	10	0.28		0.84		
	Washington Water Power Company	Yes - Kingsgate to Pacific NW		36.3	1.02				
30	WP Natural Gas (formerly CP)	Yes - Kingsgate to Oregon	See Washington Water Power Company			3.34	0.20	6.79	
	Total			913.55	25.74	877.512	29.23	930.15	